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Transcript Exhibit(s)

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JA15, JA16, JA17, JA18

EXHIBIT
JA-4
admitted

DIRECT TESTIMONY OF STEVEN GLASER
UNISOURCE ENERGY CORPORATION

DECEMBER 18, 2002

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Steven Glaser. My business address is 4350 E. Irvington Road, Tucson, AZ 85714.

Q. What is your position with Tucson Electric Power Company ("TEP")?

A. I am Senior Vice President and Chief Operating Officer of Transmission and Distribution.

Q. What are your duties and responsibilities at TEP?

A. My duties and responsibilities include overseeing all aspects of TEP's transmission and distribution systems. I am also responsible for overseeing TEP and UniSource Energy Corporation's filings and proceedings related to the Arizona Corporation Commission ("Commission").

Q. Please summarize your educational background.

A. I graduated from Georgetown University in 1980 with a BSBA degree in accounting. I then received a JD degree from the John Marshall Law School in 1983. I am a licensed member, but on inactive status, of both the Illinois and Arizona bars.

Q. Please summarize your professional experience.

A. In 1984, I became an Assistant Attorney General with the Arizona Attorney General's Office. From 1985 through 1990, I was a staff attorney in the Legal Division of the Commission. I then became employed by TEP, first as the Regulatory Affairs Attorney and then as the Manager of the Legal Department. I became the Manager of the Contracts and Wholesale Marketing Department before becoming a Vice President in 1994 and a Senior Vice President and Chief Operating Officer in 2000. One of my responsibilities since 1994 has been overseeing all transactions and filings related to the Commission. I report directly to Mr. James Pignatelli, TEP's President and Chief Executive Officer.

Q. Mr. Glaser, what is UniSource requesting in the Joint Application in this proceeding?

A. UniSource, on behalf of its designate affiliate(s) (collectively, "UniSource"), supports the Citizens Arizona Gas Division Rate Application. However, UniSource is requesting certain modifications to reflect known and measurable changes that are expected to occur as a result of UniSource's acquisition of the Citizens Arizona Gas Division assets. The primary reasons for Citizens' requested rate increase of 28.93% are a significant increase in plant expenditures for the "Build Out Program," which was authorized by the Commission, and normal growth in both the Northern Arizona Gas Division ("NAGD") and the Santa Cruz Gas Division ("SCGD"). UniSource's modified request is for an increase in gas rates of 23%, which is a significant reduction from Citizens' filed request. The reduction in the rate increase requested is due primarily to the lower rate base that will result from approval of the acquisition of the assets by UniSource. UniSource requests recovery of its investment in Citizens' gas properties, as modified by several rate base adjustments. In addition, UniSource is seeking to modify certain operating expenses. I will address UniSource's rate base and operating expense adjustments further in my testimony.

UniSource supports Citizens' proposed consolidation of the NAGD and the SCGD into a single filing and standardized tariffs across the two divisions. This mitigates the increase to SCGD gas rates without affecting the NAGD gas rates, had the regions been filed separately. In addition, as part of this consolidation, two programs which presently are available only to NAGD customers, CARES and Warm Spirit, will be expanded to include SCGD. The CARES Program provides financial assistance toward bill payment for certain residential customers through a cooperative effort with the Arizona Department of Economic Security, which qualifies eligible customers under the program. The Warm Spirit Program permits existing customers to voluntarily contribute to a fund established for assisting low-income customers with bill payment.

Q. What is the purpose of your testimony in this proceeding?

A. I am sponsoring portions of the Joint Application and will present adjustments to rate base and operating expenses in Citizens' original filing in order to reflect known and measurable changes that are expected to occur as a result of UniSource's acquisition of the Citizens Arizona Gas Division assets.

The adjustments UniSource proposes are intended to give UniSource an opportunity to earn a reasonable rate of return on the actual funds being invested in the Citizens gas properties. In doing so, gas customers will benefit from the substantial discount to net book value reflected in the negotiated purchase price. After making various line item adjustments to rate base, total rate base equals the anticipated investment by UniSource. This investment represents the adjusted base purchase price of $140.7 million and other adjustments to the base purchase price for items such as for the Griffith Plant and Accounts Receivable and Accounts Payable as listed in the Asset Purchase Agreement dated October 29, 2002 (Article 3) and as described in Mr. Pignatelli's testimony.

Q. Please describe how UniSource arrived at its adjusted base purchase price of $140.7 million.

A. UniSource's adjusted base purchase price is equal to the base purchase price specified in the Asset Purchase Agreement of $138.0 million, increased by an offset of $2.7 million to the negative acquisition premium. The offset is for anticipated asset acquisition costs, which are comprised of outside services (such as environmental survey, plant inspection, appraisals, legal, additional consulting and investment fees) and internal costs that are necessary to complete the acquisition and are incurred through the closing date. As an offset to the negative acquisition premium, these costs are capitalized and will be recovered over the average life of the assets acquired. UniSource requests that the order expressly authorize the Company to recover these costs as an offset to the negative acquisition premium, so that these costs may be capitalized for GAAP accounting purposes.

Q. Please describe the process used to evaluate Citizens' originally filed rate case.

A. The process used to evaluate Citizens' originally filed rate case consisted of the following:

1) Review of the testimony and related exhibits and the accompanying schedules;

2) Review of the preliminary due diligence and communications with Citizens' staff done prior to the Asset Purchase Agreements dated October 29, 2002;

3) Discussions with the sponsors of the Citizens testimony, exhibits and schedules to obtain an understanding of Citizens' accounting and ratemaking procedures and issues; and

4) Review of selected prior Commission orders and regulatory proceedings before the Commission.

Q. Is UniSource adopting the Citizens' rate case proceeding as originally filed?

A. UniSource is adopting the Citizens' rate case proceeding as originally filed except for the adjustments to rate base and operating expenses described below.

II. ADJUSTMENTS TO RATE BASE

Q. Please describe the rate base adjustments UniSource is proposing.

A. UniSource is proposing adjustments to Citizens originally filed rate base related to the following items.

1) Net Utility Plant in Service, based on UniSource's base purchase price for the assets, adjusted for the Griffith Generation Plant facilities (which are dedicated for service);

2) Accumulated Deferred Income Taxes ("ADIT");

3) Sale of Office Buildings; and

4) Allowance for Working Capital.

Q. Please describe the adjustment to UniSource's base purchase price for facilities dedicated to serving the Griffith Generating Plant.

A. UniSource reduced its initial Net Utility Plant in Service by $5,778,148 for the net Griffith Generating Plant Facilities which are not included in retail rate base for ratemaking purposes. The calculation of this adjustment is shown in Exhibit SG-1.

Q. Why is the Griffith Generating Plant not included in retail rate base?

A. Griffith Generating Plant is not included in retail rate base in accordance with Commission Decision No. 61835 (July 21, 1999). The Commission approved a special transportation agreement between NAGD and the Griffith Plant that provides for a monthly payment to Citizens based on levelized revenue requirements that reflect the plant investment, operating and maintenance expenses, depreciation, property taxes, income taxes and return on investment (based on the current return authorized for the NAGD). NAGD constructed, owns and operates pipeline facilities that connect the Griffith plant to two interstate pipelines. The monthly payment is compensation for constructing and operating the two interconnections. Pursuant to the Commission's order, Citizens must remove all revenues and expenses associated with the Griffith Plant during the term of the twenty-year contract.

Q. Please describe UniSource's modification to ADIT in Citizens' originally filed rate base.

A. UniSource removed Citizens' balance of ADIT of ($5,713,762). The balance of ADIT in the Citizens gas rate case filing is book and tax temporary differences related to the tax basis that Citizens has in the assets UniSource is purchasing. The deferred taxes will be realized by Citizens upon the completion of the acquisition and will not carry over from Citizens to UniSource. As of the date of the acquisition, UniSource will have no differences between book and tax basis in plant assets related to accelerated depreciation. UniSource will develop new balances of

ADIT in post-acquisition periods as temporary differences originate, as normalized taxes are billed to customers and as plant-related deferred income tax liabilities are created for financial accounting purposes (for example, when plant assets are depreciated more rapidly for tax reporting than for financial reporting).

Q. Please describe UniSource's modification to Citizens' originally filed rate base balance for the Sale of Office Buildings.

A. UniSource removed Citizens' rate base balance for the Sale of Office Buildings because UniSource's initial Net Utility Plant in Service does not include these facilities. The related amortization of this balance has been removed from operating expenses as noted below in the adjustments to operating expense as originally filed by Citizens.

Q. Please describe UniSource's modification to Citizens' originally filed rate base adjustment for Allowance for Working Capital.

A. UniSource removed all of the negative Allowance for Working Capital, which was originally filed in the amount of ($2,924,219). UniSource's modified request is for a zero Allowance for Working Capital. At the closing of the acquisition, the purchase price will be adjusted for the net of Citizens' accounts receivables, accounts payable and other assets and liabilities that are part of the working capital analysis. UniSource expects that initial working capital requirements will be positive (see the Joint Application) when the acquisition of Citizens' gas assets is complete. However, UniSource is willing to request a zero working capital requirement in order to mitigate the impact of the resulting increase in rate base.

Q. Are there any rate base adjustments which UniSource believes are appropriate as originally filed by Citizens?

A. Yes. UniSource believes Citizens' rate base adjustments for Advances for Construction, Customer Deposits, Materials and Supplies, Warm Spirit, CARES and Y2K Costs are appropriate as originally filed. The Asset Purchase Agreement provides for the adjustment of the base purchase price of $138 million for certain assets and liabilities assumed in the Citizens acquisition as of the closing date. The balances of Customer Deposits, Materials and Supplies, Warm Spirit and CARES are included in these adjustments. The Y2K Costs are a regulatory asset for deferred Y2K compliance expenses for which Citizens is seeking recovery in this rate proceeding. UniSource will be assuming this regulatory asset and any other existing regulatory assets and liabilities as appropriate when the acquisition closes. Therefore, UniSource is not proposing to adjust the balance of Y2K Costs as filed by Citizens.

III. ADJUSTMENTS TO OPERATING EXPENSES

Q. Is UniSource proposing any modifications to Citizens' originally filed operating expenses?

A. Yes. UniSource is proposing the following adjustments to Citizens' originally filed operating expenses:

1) Regulatory, Miscellaneous and Per Diem Expense;

2) Depreciation Expense; and

3) Amortization – Gain on Sale (Sale of Office Buildings).

Q. Please describe UniSource's adjustment for Regulatory, Miscellaneous and Per Diem Expense.

A. The adjustment decreases operating expense by $165,196. This amount was originally included by Citizens to capture the amortization of estimated gas rate case expense for the current Citizens filing and ongoing amortization of the Build Out Program expense approved in a prior Citizens rate case. These are Citizens expenses which will not occur going forward and therefore UniSource is not including amortization of these items in our proposed operating expense in this filing.

Q. Please describe UniSource's modification to Citizens' originally filed Depreciation Expense.

A. UniSource is decreasing Depreciation Expense by an amount of $820,674, which represents the yearly amortization of the difference between Citizens' originally filed Net Utility Plant in Service and UniSource's adjusted Net Utility Plant in Service. This adjustment is amortized at the rate of 2.67% per year, which is the weighted average of the proposed composite depreciation rates for NAGD and SCGD in Citizens' original filing (as presented in the testimony of Dr. Ronald White). *See* Exhibit SG-2 for the calculation of the weighted average depreciation rate of 2.67%.

Q. Please describe UniSource's modification to Citizens' originally filed Amortization – Gain on Sale.

A. UniSource eliminated the Amortization – Gain on Sale of ($20,886) from operating expenses. This is the amortization of the rate base balance of ($104,431) for the Sale of Office Buildings, which UniSource eliminated from rate base. UniSource removed all of Citizens' adjustment for this item because UniSource's initial Net

Utility Plant in Service does not include these facilities, as noted above in the adjustments to Citizens' originally filed rate base.

Q. Were there other expenses that UniSource reviewed but determined that adjustments were unnecessary at this time?

A. Yes, UniSource did review several other operating expense items which need no adjustment at this time, including Insurance Expense, Injuries & Damage Expense, Pension & Benefits Expense and Administrative Office Expense.

Q. Please explain why UniSource believes it is unnecessary to adjust Citizens' originally filed operating expense for Insurance Expense and Injuries & Damages Expense?

A. If UniSource made an adjustment for Insurance Expense and Injuries & Damages Expense, it would represent anticipated changes in premiums for these insurance coverages that UniSource would realize when the Citizens acquisition is complete and as Citizens operations are integrated with UniSource. UniSource has reviewed Citizens' originally filed expense for Insurance and Injuries & Damages. It is possible that UniSource will experience an increase in premiums for this insurance coverage since UniSource does not have the economies of scale for insurance coverage that Citizens has benefited from in the past. However, preliminary investigation has not produced known and measurable changes at the present time. Therefore, UniSource is not proposing a change in this operating expense at this time.

Q. Please explain why UniSource believes it is unnecessary to adjust Citizens' originally filed Pension & Benefits Expense.

A. If UniSource made an adjustment for Pension & Benefits Expense, it would represent anticipated changes in Pension and Benefits Expenses that would occur when the Citizens acquisition is complete and as Citizens operations are integrated with UniSource. UniSource has reviewed Citizens' originally filed expense for Pension & Benefits. It is possible that UniSource will experience a change in expense for this item, although UniSource anticipates that pension and benefits expense will be similar to that filed by Citizens. Preliminary investigation has not produced known and measurable changes at the present time. Therefore, UniSource is not proposing a change in this operating expense at this time.

Q. Please explain why UniSource believes it is unnecessary to adjust Citizens' originally filed Administrative Office Expense.

A. If UniSource made an adjustment for Administrative Office Expense, it would represent the anticipated changes in the allocation of corporate expenses that UniSource expects to occur when the Citizens acquisition is complete and as Citizens operations are integrated with UniSource. As originally filed by Citizens, recovery was limited to $1.2 million based on the approved Administrative Office Expense in the last litigated NAGD rate proceeding (Decision No. 58664). Pursuant to UniSource's Holding Company Order, Commission Decision No. 60480, most corporate service charges will be directly allocated and few items will actually by allocated by formula. This situation is different than how Citizens presently assigns corporate costs, as most are allocated rather than directly assigned. Without specific experience, UniSource believes at this time it is appropriate to maintain the $1.2 million of corporate allocations for ratemaking purposes.

Q. How would UniSource propose Administrative Office Expense be addressed in future rate proceedings?

A. UniSource believes this proposed treatment is unique to this rate proceeding. In future years, UniSource will be able to gather sufficient operating data to use in detailed analyses for allocation purposes. In future rate proceedings, UniSource would directly assign most costs to the appropriate corporate entity and allocate general corporate expenses to the various UniSource entities in accordance with UniSource's Holding Company Order and the related approved Cost Allocation Procedures that are currently in effect.

Q. Are there any additional modifications to the Citizens' filing that you believe are appropriate at this time?

A. Yes. I believe this is an appropriate time to address and modify the Citizens' gas facilities service line and main extension ("Line Extension") policy as reflected in their current Rules and Regulations and tariffs for service. Let me explain. In June 1994, in Decision No. 57647, the Commission approved Citizens' Build Out Program, which was a comprehensive plan to extend natural gas service to areas in Citizens' service territory that did not presently have natural gas. The Build Out Program included the necessary expenditures for pipeline mains and service lines to extend natural gas service to customers and was completed on December 31, 2001. Now that this expansion program is complete, UniSource believes it is more appropriate to modify Citizens' current Line Extension policy to be consistent with the policy of other natural gas providers in the State, for example, Southwest Gas, by providing for an economic feasibility assessment when determining under what circumstances to perform a Line Extension for any customer. *See* Exhibit SG-3 for Citizens' existing Line Extension language from its Rules and Regulations. *See* Exhibit SG-4 for UniSource's proposed Line Extension language.

IV. PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE ("PPFAC")

Q. Please describe how UniSource is proposing to modify Citizens' Arizona Electric Division's PPFAC request.

A. As discussed in the direct testimony of James Pignatelli, UniSource proposes to forego the PPFAC balance which exists at the time of closing. However, UniSource is requesting adjustment of the base rate in the PPFAC to fully recover the cost of the new Pinnacle West Capital Corporation ("PWCC") contract.

UniSource believes that the Commission should approve a PPFAC base rate which reflects the current cost of wholesale purchased power, transmission, and line losses, which would total \$.07019/kWh, for an increase of \$0.01825/kWh to the current base rate. Exhibit SG-5 identifies the cost components for both the currently effective and UniSource's proposed PPFAC base rate.

Q. Please describe the components of the existing PPFAC base rate.

A. In the existing PPFAC base rate there is a \$.04802/kWh charge for electric generation, which is intended to recover the cost of wholesale purchased power, based on wholesale purchase agreements in effect at the time of Citizens' last rate proceeding. Also included is a transmission cost of \$.00392/kWh, based on a transmission agreement with the Western Area Power Administration ("WAPA") that was in effect at the time of Citizens' last rate proceeding. These charges provide for a total PPFAC base rate of \$.05194/kWh.

Q Please describe the components of UniSource's proposed PPFAC base rate.

A. UniSource proposes a generation component adjusted for line losses and a WAPA transmission cost component. The generation rate is \$.05879/kWh, which is the fixed price in the PWCC contract. This rate is adjusted by a 10.69% loss factor, which was presented in Citizens' Amended Application to change the PPFAC, dated September 19, 2001. The resulting generation rate, adjusted for losses, is \$.06583, which represents the unit cost of generation at the customer meter. UniSource's transmission cost component is the WAPA transmission cost of \$.00436/kWh as presented in Citizens' Amended Application, which results in a total proposed PPFAC base rate of \$0.07019/kWh.

Q. Please describe UniSource's proposed treatment of the existing PPFAC bank balance.

A. As I mentioned previously, UniSource intends to forego the PPFAC balance which exists at the time of closing. This will provide significant rate relief to customers as compared to the six-year recovery of the bank balance as proposed by Citizens. At the time of Citizens' Amended Application in September 2001, the bank balance was \$87 million, in September 2002, the balance had continued to grow to \$117 million, and is projected to be \$138 million in July 2003.

Q. What does UniSource believe concerning the price in the current PWCC contract?

A. Wholesale power prices in the western U. S. were volatile in the spring of 2001, when Citizens and PWCC were negotiating contract terms. In order to mitigate Citizens' then existing variable price contract, the parties entered into a fixed price agreement. Fixing a price in those uncertain times was a reasonable option. Moreover, as a point of comparison, TEP supplies power pursuant to a five year power sale agreement signed contemporaneously with the PWCC contract that has a fixed price of $.070 per kWh.

Q. If UniSource were to successfully negotiate a reduction of any component of its proposed PPFAC base rate, how would UniSource propose to share the resulting savings with its customers?

A. UniSource would propose to modify the rate to include a 50/50 sharing of the resulting savings.

V. OFFSET TO NEGATIVE ACQUISITION PREMIUM FOR ELECTRIC ASSETS

Q. UniSource addressed an offset for the negative acquisition premium for the Citizens' gas assets. Does UniSource propose any similar treatment related to acquiring Citizens' electric assets?

A. Yes, UniSource proposes that a $1.8 million offset to the negative acquisition premium be approved to address recovery of the anticipated asset acquisition costs related to the Citizens' electric assets, which are comprised of outside services (such as environmental survey, plant inspection, appraisals, legal, additional consulting and investment fees) and internal costs that are necessary to complete the acquisition and are incurred through the closing date. As an offset to the negative acquisition premium, these costs are capitalized and will be recovered over the average life of the assets acquired. UniSource requests that the order expressly authorize the Company to recover these costs as an offset to the negative acquisition premium, so that these costs may be capitalized for GAAP accounting purposes.

Q. Does this conclude your testimony?

A. Yes.

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UNISOURCE ENERGY CORPORATION **Exhibit SG-1**

ADJUSTMENTS TO UTILITY PLANT IN SERVICE

Description	Amount	Source
Griffith Plant in Service		
Transmission Plant, Original Cost	$5,963,981	Schedule B4-A, Adj. A, Line 39 \1
Transmission Plant, Accumulated Depreciation	($185,833)	Schedule B4-B, Adj. A, Line 39 \1
Net Plant in Service	$5,778,148	
Adjusted Base Purchase Price	$140,700,000	
Griffith Plant Removal	($5,778,148)	
Total Adjusted Purchase Price for Utility Plant in Service	**$134,921,852**	

\1 Originally filed Citizens gas rate case schedules, as revised 9/20/02 (Northern Arizona Gas Division and Santa Cruz Gas Division Combined).

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UNISOURCE ENERGY CORPORATION **Exhibit SG-2**

WEIGHTED PROPOSED COMPOSITE DEPRECIATION RATES

Rate Base Weighting			Source	
NAGD: Rate Base - Gross Utility Plant in Service	$211,754,534	93.6%	Schedule B-1, Line 1	\1
SCGD: Rate Base - Gross Utility Plant in Service	$14,363,808	6.4%	Schedule B-1, Line 1	\2
	$226,118,342	100.0%		

Proposed Composite Depreciation Rates			Weighted
NAGD	2.72%	93.6%	2.55%
SCGD	1.97%	6.4%	0.13%
Weighted Average Combined Composite Rate			**2.67%**

\1 Northern Arizona Gas Divison - originally filed Citizens gas rate case schedules, as revised 9/20/02.

\2 Santa Cruz Gas Divison - originally filed Citizens gas rate case schedules, as revised 9/20/02.

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CITIZENS UTILITIES COMPANY
NORTHERN ARIZONA GAS DIVISION Original Sheet 20
SECTION NO. 7
EXTENSION OF LINES
A. General Requirements

1. The Company shall install necessary facilities to provide gas to applicants for service under a general service rate schedule in accordance with this Section wherever such service can be rendered through normal extension of its system.

2. Applications for new service must be made to the Company office nearest to the premises for which service is desired. After receipt of the application, the Company shall determine the extent of the facilities required to provide the service, the estimated cost of such facilities and the number of potential new Customers willing to connect to service immediately upon completion of the extension if a list of potential new Customers is furnished by the initial applicant. To be included, each existing potential new Customer must request service prior to the installation of the extension and must demonstrate the capability for using such service through a major gas burning appliance such as a water heater or furnace. The design and the resultant cost of facilities shall be based on the delivery of gas in the required volumes from the nearest adequate source in accordance with the Company's standard engineering and construction practices and shall include mains and any special crossings, distribution or city gate metering and regulating facilities and upgrading of existing facilities which may be required. Individual service lines and Customer metering and regulating equipment shall not be included. A copy of the estimate shall be furnished to the applicant upon request.

3 . If the length of the extension from the point of beginning to the junction of the service line to the furthest Customer to be served is less than an allowance of 100 feet multiplied by the number of existing potential new Customers connected to service, it shall be installed free of charge. A greater allowance for non-residential Customers shall be subject to the provisions of subsection (4) below. Extensions of greater length will be installed by the Company if the applicant has made a refundable advance to compensate for the excess length. The amount of the advance shall be the difference between the total cost of the facilities and an amount determined by multiplying the average cost of the extension per foot (total cost divided by total length) by the number of existing potential new Customers

committed to service and then multiplying that product by 100 or by an amount calculated pursuant to subsection (4) below or by a combination of the allowance thereof. The applicant shall have 90 calendar days after notification of the amount required to execute an Extension Agreement on the Company's form. At the end of that time, the Company may revise its estimates to reflect any changes in costs or conditions which will affect the amount of the advance. The Company shall waive any advance of less then $50.00.

4 . The allowance for non-residential Customers will apply to those served under a general service rate schedule which does not specifically provide for interruptible service. The allowance for a qualifying non-residential Customer shall be the greater of an amount equivalent to the cost of 100 feet or an amount determined by an economic feasibility analysis which shall consider the incremental revenues and costs associated with the main extension. The incremental costs shall include both direct and allocated costs and cost of capital as approved in the Company's most recent rate proceeding before the Arizona Corporation Commission.

5 . Applications for new service located in mobile home parks shall be treated as a request from one of a group of Customers. The Company shall prepare an estimate based on Company ownership of the distribution system in the park and individual service and metering at each unit. Mains must be installed in dedicated streets or in easements provided by the property owner on a mutually acceptable easement form.
Applicants for temporary service from existing mains or from main extensions must make a non-refundable contribution of the entire cost of facilities required to provide and disconnect service. The estimate shall include such items as individual service and metering equipment and removal costs less salvage.

6 . Contributions and advances must be made by cash, surety bond, or similar alternative acceptable to the Company, such as a Certificate of Deposit. After the agreement has been signed and payments received, the Company shall have a reasonable length of time, not to exceed six months, to complete construction of its facilities except when any delay is caused by:
a. Failure of the applicant to provide or the Company to secure any necessary rights-of-way, approvals or permits;
b . Inability to get delivery of material ordered on a timely basis;
c. Contracting or scheduling problems beyond the Company's reasonable control, including strikes, lockouts, governmental intervention, acts of God and similar causes; and
d . Failure of the applicant to commence the development of the property to be served or, in case of a new subdivision, failure of the subdivider to properly prepare the areas in which the facilities are to be installed.

7 . Nothing in this section shall prohibit the Company from installing facilities from a different source or of a different size or kind so long as the cost of construction is greater than the estimate on which any advance or contribution is based.

8 . After the construction has been completed and closed to plant records, the Company shall review the record of the work. If the actual cost as closed to the Company's plant record varies by $50 or more from the estimate on which the advance or contribution is based, the total difference shall be refunded if the estimate was more or collected if the estimate was less. This initial cost review shall not be applicable unless the facilities actually installed were the same as those upon which the advance was made. In addition, the Company shall, upon request, refund to each residential Customer the difference between the original cost of 100 feet of extension (actual cost divided by actual footage multiplied by 100) and the number on which the initial advance was made; and, for each non-residential Customer shall refund the difference between the original cost of 100 feet of extension (actual cost divided by actual footage multiplied by 100) and the number on which the initial advance was made or an amount calculated pursuant to the provisions of subsection (4) above.

9 . Upon request, the Company shall annually review the extension agreement. At each review, the number of Customers then served directly from the extension shall be compared with the number served on the last prior review date. A refund, calculated in accordance with the above provisions, shall be given for each additional Customer served. The Company may, at its sole option, make refunds at any time. On or shortly after the fifth anniversary of the date the facility was placed in service, the Company will review the record of the extension and make a final disposition of any remaining advance. A final refund will be made for additional Customers in the same manner as provided for interim refunds.

10. Any unrefunded amount will be retained as a contribution and the Extension Agreement terminated. In no case shall the total of any refunds be greater than the amount of the advance. No interest will be paid on any advance.

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PROPOSED SECTION NO. 7
EXTENSION OF LINES

Extensions of gas distribution services and mains necessary to furnish permanent service to applicants will be made in accordance with this rule.

A. GENERAL

The Utility will construct, own, operate and maintain service and main line extensions.

1. Gas service lines will be of suitable capacity from the Utility's gas main to a meter location on the property of the applicant that is satisfactory to the Utility

2. Gas distribution main extensions will be only along public streets, roads, and highways, which the Utility has legal right to occupy, and on public lands and private property across which rights-of-way, satisfactory to the Utility, may be obtained.

B. SERVICE AND MAIN EXTENSIONS TO APPLICANTS FOR SERVICE

1. General Policy – All service line and main line extensions are made on the basis of economic feasibility except those for master-metered mobile home parks (MMP), whose extensions shall be made in accordance with the provisions in Section B.3 hereof. The economic feasibility will be calculated by the Incremental Contribution Method as described in Section B.4 hereof. However, at a minimum, the Utility will extend 30 feet of main for each applicant who connects a functioning water heater or furnace within 4 months of the completion of the main.

2. Facility Charge – If any applicant fails to use natural gas for equipment stated in the application and used as the basis for estimating the allowable investment within 4 months of the completion of the main, the Utility may calculate and bill the applicant and the applicant shall pay within 45 days a nonrefundable Facilities Charge according to the Utility's extension rule in effect at the time the extension was made as though service had been requested on the basis of the actual equipment installed and utilized. At its option, the Utility may require a performance bond or other surety guaranteeing bona fide operation of the facility for which the extension is requested in accordance with applicant's representation in the contract.

3. If the residential customers are tenants in a fully improved MMP and the MMP is currently or was formerly served as a master-metered mobile home park, the allowable investment for the MMP will be determined by the following formula:

$$AI = (FR - CR) \times 5$$

where:

AI = Allowable Investment

FR = The MMP's estimated future total annual revenue, assuming conversion to individual residential service, using the MMP's average park occupancy for the past two years, less the Utility's current average cost of purchased gas.

CR = The MMP's current total annual revenue, under the applicable schedule, averaged for the past two years, less the Utility's current average cost of purchased gas. If the MMP is not a current customer of the Utility, the CR will be determined on the basis of engineering estimates of occupancy and usage.

The Utility will install that portion of each service in excess of the allowance subject to a nonrefundable contribution to be paid prior to construction by the applicant MMP. In no event shall costs above the allowable investment be borne by the Utility.

4. Incremental Contribution Method – Gas service line and main line extensions will be made by the Utility at its expense for the allowable investment as calculated by an Incremental Contribution Study (ICS).

   a. Allowable investment shall mean a determination by the Utility that the revenues less the incremental gas cost to serve the applicant customer provides a rate of return on the Utility's investment no less that the most recent overall rate of return authorized by the Commission in a general rate case for the Utility. If there is not an explicit rate of return authorized, a 9% rate will be used.

   b. All applicants will pay for the entire length of their service lines on their property. If the ICS has an allowable investment that is more than the cost of the main extension, then the excess will be applied evenly to all applicants to reduce their cost of service line installation.

   c. The Utility, after conducting an ICS, may at its option, extend its facilities to Customers whose usage does not satisfy the definition of Economic Feasibility but who otherwise are Permanent Customers provided such Customer signs an extension agreement and advances as much of the cost, and/or agrees to pay a nonrefundable Facility Charge necessary to make the extension economically feasible.

   d. Applicants may provide trench for service lines and/or mains to the Utility's specifications and the Utility costs will be reduced by an amount equal to this avoided cost in the ICS.

   e. Customers provided with line extensions using the Incremental Contribution Method shall be reviewed annually for a period of five years to determine the amount of any refund as described in Section B5.

5. Method of Refund

Amounts advanced by the customer(s) in accordance with this rule, less any unpaid Facility Charges, shall be refunded, without interest, in the following manner.

a. Refunds of an advance shall be made for each additional separately metered permanent service connected to the main extension for which an advance was collected when an excess allowable investment is calculated by an ICS that includes the additional customers(s). The calculation will use actual usage for existing customers. Future years usage will be estimated on actual usage adjusted for normal weather.

b. Customers adding on to an existing main covered by an extension agreement, still subject to refund, will pay the entire cost of their service line, will contribute an advance equal to the average advance, minus any refunds, provided by the existing contributors, and will be eligible for refunds of advances in subsequent annual reviews.

c. No refunds will be made for additional customers connecting to a further extension or series of extensions constructed beyond the original extension.

d. Refunds will be made annually or intermittently within the annual period at the option of the Utility. Amounts to be refunded may be accumulated by the Utility to a maximum of $50 per customer, or the total refundable balance if less than $50 per customer. Refunds will only be made to customers, the assignees of customers, or developers.

e. When two or more parties make a joint advance on the same extension, refundable amounts will be distributed to these parties in the same proportion as their individual percentages of the total joint advance.

f. The refund period shall be five years from the date of the completion of the extension. No refunds will be made by the Utility after the termination of the refund period. Any portion of the advance that remains unrefunded at the end of the refund period shall remain the property of the Utility.

g. Any assignment by a customer of their interest in any part of an advance, which at the time remains unrefunded, must be made in writing and approved by the Utility.

h. Amounts advanced under a gas main extension rule previously in effect will be refunded in accordance with the provisions of such rule.

C. SERVICE AND MAIN EXTENSIONS TO SERVE INDIVIDUALLY-METERED SUBDIVISIONS, TRACTS, HOUSING PROJECTS, MULTI-FAMILY DWELLINGS AND MOBILE HOME PARKS OR ESTATES

1. Advances

a. Gas distribution service and main extensions to and within individually metered subdivisions, housing projects, multi-family dwellings and mobile home parks or estates will be constructed, owned and maintained by the Utility in advance of applications for service by bona fide customers only when the entire estimated cost of such extensions as determined by the Utility is advanced to the Utility, and a main extension contract is executed. This advance may include the cost of any gas facilities installed at the Utility's expense in conjunction with a previous service or main extension in anticipation of the current extension.

b. When a subdivider/builder/developer is building a project in consecutive phases such that each phase is constructed separately and requires separate advances, unused allowances from one phase may be applied to an outstanding advance in any other phase so long as such outstanding advance is still eligible for refund.

c. For developers who have entered into a line extension agreement and facilities have been installed and then they or some other party request subsequent reconfiguring of facilities or other changes requiring additional expenditures by the Utility, these new costs will be entirely paid for with a non-refundable advance and any refunds will be made in accordance with the original agreement. No additional agreement or extension of the time for refunds will be made to cover the area piped under the original extension agreement.

d. See, Section B3 for governing requests to serve MMP through individual residential meters if the MMP is currently or was formerly served under a MMP schedule.

e. Refunds will be made to developers as described in Section B5.

D. GENERAL CONDITIONS

1. Postponement of Advance

The Utility, at its option, may postpone, for a period not to exceed five years, that portion of an advance which it estimates would be refunded under the provisions of this rule. At the end of such refund period, the Utility shall collect all such amounts not previously advanced which were not then refundable. When advances are postponed, the applicant may be required to furnish to the Utility evidence of the necessary approvals to commence construction and of adequate financing. A surety bond satisfactory to the Company, or other Utility-approved surety, may be required to assure payment of any postponed amounts at the end of the postponement period.

2. The applicants or developer will provide property location, tax-identification numbers and other property information helpful to planning an extension.

3. Contracts

a. Each applicant requesting an extension in advance of applications for service will be required to execute a contract covering the terms under which the Utility will install main lines in accordance with the provisions of the tariff schedules.

b. At the time service is requested, the applicant will submit a list of natural gas equipment to be used including the Btu input.

4. One Service for a Single Premise

a. The Utility will not install more than one service line to supply a single premise, unless it is for the convenience of the Utility or an applicant requests an additional service, and in the opinion of the Utility, an unreasonable burden would be placed on the applicant if the additional service were denied. When an additional service is installed at the applicant's request, the applicant shall make a nonrefundable contribution for the additional service based on the Utility's estimated cost.

b. When a service extension is made to a meter location upon private property which is subsequently subdivided into separate premises, with the ownership portions thereof divested to other than the applicant or the customers, the Utility shall have the right, upon written notice, to discontinue service without obligation or liability. Gas service, as required by said applicant or customer, will be reestablished in accordance with the applicable provisions of the Utility's rules.

5. Branch Services

The Utility, at its option, may install a branch service for units on adjoining premises.

6. Main Extension Agreement Requirements

a. Upon request by an applicant for a main extension, the Utility shall prepare, without charge, a preliminary sketch and rough estimate of the cost of the installation to be advanced by the applicant.

b. Any applicant for a main extension requesting the Utility to prepare detailed plans, specifications, or cost estimates may be required to deposit with the Utility an amount equal to the estimated cost of preparation. The Utility shall, upon request, make available within 90 days after receipt of the deposit referred to above, such plans, specifications, or cost estimates of the proposed main extension. Where the applicant authorizes the Utility to proceed with the construction of the extension, the deposit shall be credited to the cost of construction; otherwise, the deposit shall be nonrefundable. If the extension is to include oversizing of facilities to be done at the Utility's expense, appropriate details shall be set forth in the plans, specifications and cost estimates. Subdividers providing the Utility with approved plans shall be provided with plans, specifications or cost estimates within 45 days after receipt of the deposit referred to above.

c. Where the Utility requires an applicant to advance funds for a main extension, the Utility shall furnish the applicant with a copy of this rule prior to the applicant's acceptance of the Utility's extension agreement.

d. All main extension agreements requiring payment by the applicant shall be in writing, signed by each party and shall include the following.

(1) Name and address of applicant(s).

(2) Proposed service address(es) or location(s).

(3) Description and sketch of the requested main extension.

(4) Description of requested service.

(5) A cost estimate to include materials, labor, and other costs as necessary.

(6) Payment terms.

(7) A concise explanation of any refunding provisions, if applicable.

(8) The Utility's estimated start date and completion date for construction of the main extension.

(9) A summary of the results of the Incremental Contribution analysis performed by the Utility to determine the amount of advance required from the applicant for the proposed main extensions.

(10) Each applicant shall be provided a copy of the approved main extension agreements.

7. Relocation of Services and Mains

   a. When, in the judgment of the Utility, the relocation of a main or service is necessary and is due either to maintenance of adequate service or the operating convenience of the Utility, the Utility shall perform such work at its own expense.

   b. If relocation of a main or service line is due solely to meet the convenience or the requirements of the applicant or the customer, such relocation, including metering and regulating facilities, shall be performed by the Utility at the expense of the applicant or the customer.

   c. Relocation of facilities will be mandatory and at the customer's expense when actions of the customer restrict the Utility's access to or the safety of the facility.

8. Standby Service or Residential Pool Heating

   No allowance will be made for equipment used for standby or emergency purposes only.

9. Temporary Service

   Extensions for temporary service or for operations, which in the opinion of the Utility are of a speculative character or of questionable permanency will will require an advance for the entire cost of the facilities required, with provision for a refund with the use of an ICS calculated annually or at the termination of the temporary service.

10. Length and Location

   The length of main or service required for an extension will be considered as the distance along the shortest practical and available route, as determined by the Utility, from the

Utility's nearest permanent distribution main.

11. Service Impairment to Other Customers

When, in the judgment of the Utility, providing service to an applicant would impair service to other customers, the cost of necessary reinforcement to eliminate such impairment may be included in the cost calculation for the extension.

12. Service From Transmission Lines

The Utility will not tap a gas transmission main except when conditions in its sole opinion justify such a tap. Where such taps are made, the applicant will pay the Utility the cost of such tap, and extensions therefrom will be made in accordance with the provisions of this rule.

13. Other Types of Connections

Where an applicant or customer requests a type of service connection other than standard such as curb meters and vaults, etc., the Utility will consider each such request and will grant such reasonable allowance as it may determine. The Utility shall install only those facilities that it determines are necessary to provide standard natural gas service in accordance with this tariff. Where the applicant requests the Utility to install special facilities which are in addition to, or in substitution for, or which result in higher costs than the standard facilities which the Utility would normally install, the extra cost thereof shall be borne by the applicant.

14. Excess Flow Valve Installation Option

In accordance with Title 49, Section 192.383 of the Code of Federal Regulations, the installation of an excess flow valve, as defined in Rule No. 1, shall be performed by the Utility on a new or replaced single residence service line at the request of a customer. The installation of an excess flow valve is not mandatory; if a customer elects this installation, the Utility shall perform the installation subject to the customer assuming responsibility for all costs associated with installation, maintenance and replacement. Each customer requesting the installation of an excess flow valve will be required to execute a written agreement.

15. Exceptional Cases

In unusual circumstances, when the application of this rule appears impractical or unjust to either party, the Utility or the applicant may refer the matter to the Commission for special ruling or for the approval of special conditions which may be mutually agreed upon, prior to commencing construction.

16. Taxes Associated with Nonrefundable Contributions and Advances

Any federal, state or local income taxes resulting from a nonrefundable contribution or advance by the customer in compliance with this rule will be recorded as a deferred tax and appropriately reflected in the Utility's rate base. These deferred taxes will be amortized over the remaining tax life of the asset.

5

UNISOURCE ENERGY CORPORATION

Exhibit SG-5

PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE
RATE COMPONENTS

		$/kWh	
Current PPFAC Base Rate			
Cost of Electric Generation		$0.04802	\1
Cost of WAPA Transmission		$0.00392	\1
Total Current Rate		$0.05194	
Increase in Cost of Generation			
APS contract cost of generation (a)	(a)	$0.05879	\1
Loss Factor (b)	(b)	10.69%	\1, \2
Cost of Electric Generation at Meter	a / (1 - b)	$0.06583	
Increase in Cost of Generation		$0.01781	
Increase in WAPA Transmission			
Increase in WAPA Transmission		$0.00044	\1
Current Cost of WAPA Transmission		$0.00436	\1
Increase in PPFAC Base Rate		**$0.01825**	
Proposed PPFAC Base Rate		**$0.07019**	

\1 Citizens' Amended Application for the Purchased Power and Fuel Adjustment Clause dated September 19, 2001.

\2 Approved Losses Rate from Citizens' last rate case.

EXHIBIT
JA-5
Admitted

REBUTTAL TESTIMONY OF STEVEN GLASER
UNISOURCE ENERGY CORPORATION

APRIL 28, 2003

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Steven Glaser. My business address is 4350 E. Irvington Road, Tucson, AZ 85714.

Q. Did you file direct testimony on behalf of UniSource Energy Corporation ("UniSource") in this Docket?

A. Yes. I filed direct testimony on December 18, 2002.

Q. What is the purpose of your rebuttal testimony?

My testimony addresses proposed modifications to the Settlement Agreement as recommended in the testimony of the Residential Utility Consumer Office ("RUCO") witness, Ms. Marylee Diaz Cortez.

Q. What recommendations did Ms. Diaz Cortez propose in her testimony?

A. Although RUCO was supportive of the Settlement Agreement, Ms. Diaz Cortez did propose the following changes: (1) modify allocation of any savings that may be realized in a Pinnacle West Capital Corporation ("PWCC") contract renegotiation from 60/40 percent to 90/10 percent for Customer/UniSource, respectively; and (2) increase expenditures for Demand Side Management ("DSM") programs from the current level of $175,000 per year to $600,000 and potentially to $1,000,000 per year.

Q. With regards to how savings that result from a potential renegotiation of the PWCC contract are allocated, would you consider a change from a 60/40% sharing to a 90/10% sharing reasonable?

A. No, it is not reasonable to make such a significant change to a single component in the Settlement Agreement.

Q. Why do you believe that such a request is unreasonable?

A. The proposed settlement that has been reached was the culmination of many discussions and bargaining regarding multiple issues. To change a single component, rather than viewing the settlement as a whole, would upset the balance achieved by the parties in the settlement process. As in most complex negotiations, throughout the negotiations, the parties weighed the issues and where acceptable, compromised positions initially taken in order to reach agreement. One needs to look no further than the content of the Joint Application and the elements of this Settlement Agreement to find examples. UniSource conceded to numerous modifications including: (1) a $10 million permanent reduction to the gas rate base; (2) restrictions in the financing provisions; and (3) a three-year gas and electric rate moratorium. (This is particularly noteworthy because Citizens' base electric rates have not been increased since January 1997.)

This settlement as a whole benefits Citizens' customers in substantial ways. Citizens' electric customers will not be asked to pay for any increases in power costs through the closing of this transaction, because UniSource has agreed to forfeit its right to pursue the undercollected Purchase Power and Fuel Adjustor Clause ("PPFAC") balance from the Citizens customers. This amount is estimated to be approximately $135 million by the end of July 2003. A further benefit of the settlement is that Citizens' gas customers will have use of approximately $30.7 million of facilities and Citizens' electric customers will have use of approximately $93.6 million of facilities that they will never have to pay for because UniSource has agreed not to seek recovery of the negative acquisition adjustments.

Rather than looking at a single component of the proposed settlement in a vacuum, the overall significant beneficial outcome should be the key consideration. Therefore, I urge the Commission to view the 60/40 percent PWCC contract savings allocation as part and parcel of the entire settlement package.

Q. What are your concerns regarding RUCO's proposal that the funding of DSM be increased significantly?

A. DSM programs help customers to use energy more efficiently, which should help them reduce their power bills. This is a worthwhile goal; however, in recent years, there have been some significant differences of opinion as to the best way to assist consumers with this endeavor. As I will discuss, the Commission will be providing further direction on these issues in the near term. Therefore, to significantly increase the amount of funds Citizens is currently working with for DSM programs is premature.

Q. How has DSM policy evolved over time?

A. DSM gained momentum in the electric utility industry in the early 1990's. Early DSM programs were focused on offering rebates to consumers who purchased energy efficient electric equipment. For the past five to seven years, the utility industry in Arizona has shifted the DSM focus from rebate programs to market-based solutions, such as TEP's Guarantee Home Program and renewable energy resources. Moreover, in the Commission's Environmental Portfolio Standard ("EPS") order, Decision No. 62506, the Commission has supported the renewable energy approach and authorized Arizona utilities to shift funding from DSM programs to renewable energy resources.

Q. Why did the industry shift to market-based DSM programs?

A. One reason for the shift is that most rebate programs only create short-term changes in behavior, while market-based solutions and consumer education programs result in long-term behavioral changes (market transformation). Market-based solutions are driven by customer choice, given the combination of the customers' particular circumstances based on load patterns, awareness and economics. Over the years, the Commission has expressed an interest in moving to market-based DSM programs. For example, in TEP's last general rate case, Decision No. 59594, in a settlement between TEP, Staff, RUCO, and others, the parties agreed to a shift in DSM focus from rebate programs to self-funded, market-based solutions. We believe that market-based solutions are driven by customer economics, thus reducing the need for additional subsidization of DSM programs through a charge on a consumer's bill.

Q. How much is Citizens currently collecting in rates for DSM program costs?

A. Citizens' original proposal in its last electric rate case was a DSM program to be funded $800,000 annually. However, in Decision No. 59951, the Commission approved $175,000 annually for on-going DSM program costs. In addition, Citizens received approval to collect $200,000 annually for previously deferred DSM costs. Currently there is approximately $1,000,000 remaining in the deferral account.

Q. Generally, how has the Environmental Portfoloio Standard decision affected DSM funding?

A. TEP and Arizona Public Service ("APS") have shifted dollars from DSM funding to meet the EPS requirements. In its Decision, the Commission found:

- The Affected Utilities should utilize existing SBC (System Benefit Charges) monies to fund the EPS; and

- Monies for DSM programs should be redirected to renewables.

For example, starting in 2000, TEP has shifted DSM funds from DSM programs to renewable energy resources. The decision established the funding level for TEP's EPS as follows:

Year	EPS Funding Level	DSM Funding Level
2000	$1,500,000	$1,600,000
2001	$1,600,000	$1,500,000
2002	$1,800,000	$1,300,000
2003	$2,000,000	$1,100,000
2004 – 2007	$2,250,000	$850,000

Q. Does UniSource believe that RUCO's proposal that the Citizens' properties be required to have $1,000,000 in DSM funding is comparable to funding levels of other Arizona utilities?

A. No. UniSource believes that the current DSM funding level for Citizens is appropriate based on a cost per customer analysis. The following chart develops a cost-per-customer comparison. It compares TEP's, APS' and Citizens' current programs, as well as the RUCO proposal by comparing the approximate level of current DSM funding to the number of customers.

	TEP	APS	Citizens - Current	Citizens-RUCO's Proposal
Current DSM Level	$1,300,000	$394,393	$175,000	$1,000,000
Customers	359,372	903,089	77,818	77,818
Cost per Customer	$3.62	$0.44	$2.25	$12.85

I would also note that TEP's DSM spending-per-customer would continue to decrease as the dollars allocated to EPS increases. In 2004, TEP estimates the cost per customer for DSM spending will be $2.27.

Q. Has the Commission addressed the issue of DSM in recent dockets?

A. Yes. DSM policy was discussed during the Track B workshops and hearing. Ultimately, the Commission found, "We will therefore direct Staff to facilitate a workshop process to explore the development of a DSM policy and an environmental risk management policy, with such exploration to include an examination of the possible costs and benefits of the respective policies, and to file a report, within 12 months from the date of this Decision, informing the Commission of the progress achieved in the workshops." (Decision No. 65743).

Q. What is UniSource's conclusion?

A. UniSource believes that Citizens' current level of DSM spending is appropriate. However, UniSource is willing to work with Staff, RUCO and other interested parties to review the design and allocation of DSM funding.

I also believe it is prudent and in the public interest for the Commission to conduct a comprehensive review examining the costs and benefits of DSM policy before requiring

UniSource to make a substantial funding increase, a cost that will ultimately be borne by customers.

Q. Does this conclude your testimony?

A. Yes.

LEWIS AND ROCA LLP
LAWYERS

EXHIBIT
JA-6
admitted

BEFORE THE ARIZONA CORPORATION COMMISSION

MARC SPITZER
Chairman

JIM IRVIN
Commissioner

WILLIAM A. MUNDELL
Commissioner

MIKE GLEASON
Commissioner

JEFF HATCH-MILLER
Commissioner

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DOCUMENT CONTROL

IN THE MATTER OF THE APPLICATION OF THE ARIZONA ELECTRIC DIVISION OF CITIZENS COMMUNICATIONS COMPANY TO CHANGE THE CURRENT PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE RATE, TO ESTABLISH A NEW PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE BANK, AND TO REQUEST APPROVED GUIDELINES FOR THE RECOVERY OF COSTS INCURRED IN CONNECTION WITH THE ENERGY RISK MANAGEMENT INITIATIVES.	DOCKET NO. E-01032C-00-0751
IN THE MATTER OF THE APPLICATION OF CITIZENS COMMUNICATIONS COMPANY, ARIZONA GAS DIVISION, FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTIES FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO PROVED SUCH RATE OF RETURN.	DOCKET NO. G-01032A-02-0598

LEWIS AND ROCA LLP

LAWYERS

IN THE MATTER OF THE JOINT APPLICATION OF CITIZENS COMMUNICATIONS COMPANY AND UNISOURCE ENERGY CORPORATION FOR THE APPROVAL OF THE SALE OF CERTAIN ELECTRIC UTILITY AND GAS UTILITY ASSETS IN ARIZONA, THE TRANSFER OF CERTAIN CERTIFICATES OF CONVENIENCE AND NECESSITY FROM CITIZENS COMMUNICATIONS COMPANY TO UNISOURCE ENERGY CORPORATION, THE APPROVAL OF THE FINANCING FOR THE TRANSACTIONS AND OTHER RELATED MATTERS.	DOCKET NO. E-01933A-02-0914 DOCKET NO. E-01032C-02-0914 DOCKET NO. G-01032A-02-0914 **NOTICE OF FILING SETTLEMENT AGREEMENT**

Pursuant to the Procedural Order dated February 7, 2003, Joint Applicants file the attached signed Settlement Agreement between the Staff of the Utilities Division, UniSource Energy Corporation, Tucson Electric Power, and Citizens Communications Company.

Respectfully submitted this 1st day of April, 2003.

LEWIS AND ROCA LLP

By Michael T Hallam

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ORIGINAL AND seventeen (17) copies of the foregoing hand-delivered this 1st day of April, 2003, to:

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1385583.1

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SETTLEMENT AGREEMENT

UNISOURCE ENERGY CORPORATION'S

ACQUISITION OF CITIZENS COMMUNICATION COMPANY'S

GAS AND ELECTRIC UTILITY ASSETS

Staff of the Utilities Division ("Staff") of the Arizona Corporation Commission ("Commission"), Citizens Communications Company ("Citizens"), a Delaware corporation, UniSource Energy Corporation, an Arizona corporation ("UniSource"), Tucson Electric Power Company ("TEP"), an Arizona corporation (collectively "the Parties") agree to the following proposed settlement agreement ("Agreement") of the matters pending in Docket Nos. G-01032A-02-0598 ("Gas Rate Case"), E-01032C-00-0751 ("PPFAC Case"), and E-01933A-02-0914, E-01302C-02-0914, G-01302C-02-0914 ("Joint Application") (collectively, "Consolidated Cases"). The Parties recognize that this Agreement is a proposed settlement, thus is subject to the approval and/or the terms placed upon it by the Commission.

WHEREAS, Citizens currently provides natural gas service in Santa Cruz County, Coconino County, Navajo County, Yavapai County and Mohave County and electric service in Santa Cruz County and Mohave County and UniSource desires to purchase Citizens' electric utility assets in Arizona and Citizens' gas utility assets in Arizona.

WHEREAS, all intervenors were provided notice of the settlement process, including notice of meetings involving all intervenors and with opportunity to participate and comment.

WHEREAS, the Parties have conducted discovery and have analyzed that discovery and all materials filed in the Consolidated Cases, and the proposed settlement set forth in this Agreement is based upon that analysis.

WHEREAS, UniSource will create one or more wholly-owned subsidiaries to own and operate the electric utility assets and the gas utility assets purchased from Citizens. For purposes of this Agreement, the subsidiary or company created to own and operate the gas utility assets shall be referred to as "GasCo" and the subsidiary or company created to own and operate the electric utility assets shall be referred to as "ElecCo." GasCo and ElecCo, for purposes of this Agreement, shall be collectively known as the "New Companies." UniSource may create an intermediate holding company ("HoldCo") to finance and own the New Companies.

WHEREAS, the Parties desire to adopt this Agreement to allow Citizens to transfer to GasCo its Certificate(s) of Convenience and Necessity ("CC&N") to provide natural gas service in Arizona and its Arizona assets related to Citizens' gas utility business in Arizona ("Gas Assets"), as further set forth in the Asset Purchase Agreement dated October 29, 2002, between Citizens and UniSource, relating to the purchase of the Gas Assets ("Gas Asset Purchase Agreement").

WHEREAS, the Parties desire to adopt this Agreement to allow Citizens to transfer to ElecCo its CC&N(s) to provide electric service in Arizona and its Arizona assets related to Citizens' electric utility business in Arizona ("Electric Assets"), as further set forth in the Asset Purchase Agreement dated October 29, 2002, between Citizens and UniSource, relating to the purchase of the Electric Assets ("Electric Asset Purchase Agreement").

WHEREAS, the Parties agree that nothing in this Agreement is intended to, in any way, restrict or modify the Commission's current authority or jurisdiction over the New Companies, Citizens and TEP as provided under Arizona law.

WHEREAS, the Parties agree that this Agreement is in accordance with A.R.S. §§ 40-301 *et seq.*, A.R.S §§ 40-281 *et seq.*, A.A.C R14-2-803 and R14-2-804.

WHEREAS, the Parties agree that adoption of this Agreement is in the public interest for the following reasons:

(a) UniSource shall, as part of this Agreement, forfeit its right to pursue the recovery from retail ratepayers of any of the under-collected Purchase Power and Fuel Adjustor Clause ("PPFAC") balance, currently the subject of Docket No. E-01032C-00-0751, up through and including the date of the closing of the purchase of Citizens' Electric Assets and Gas Assets by UniSource. The forfeited PPFAC balance is currently estimated to be at least $135 million as of July 28, 2003. Regardless of the actual amount of the PPFAC balance that exists at the time of the closing of the purchase of Citizen's Electric Assets and Gas Assets by UniSource, the right(s) to recover from retail ratepayers shall be forfeited by UniSource, any of its subsidiaries, and Citizens.

(b) In Docket No. G-01032A-02-0598, the Gas Rate Case, Citizens had originally requested an increase in revenue requirement of

$21,005,521, or a rate increase of 28.9 percent. Under this Agreement, GasCo shall only receive an increase in the revenue requirement of $15,191,276, or an increase of approximately 20.9 percent.

(c) Included is a $10 million permanent reduction to the gas rate base amount due to a disallowance to the Buildout Program, thereby reducing the revenue that needs to be recovered from ratepayers.

(d) Financing provisions will be in place to allow UniSource to purchase the Electric Assets and Gas Assets while ensuring that the New Companies, TEP and their customers will not be harmed by the acquisition by UniSource.

(e) UniSource shall put into place a procedure to commence the process of opening up the new ElecCo's service territories to retail electric competition by no later than December 31, 2004.

(f) TEP shall provide a feasibility study and written plan to consolidate or, in the alternative, coordinate the operations of ElecCo in Santa Cruz County with the operations of TEP when TEP files its next general rate case. This study shall explore means to improve operations, efficiency and service for the Santa Cruz County ElecCo customers. In determining the feasibility of such a plan, TEP will consider the impact of consolidation on two-county bond financing.

(g) UniSource shall ensure participation by ElecCo in the Environmental Portfolio Standard ("EPS").

(h) UniSource shall take measures described in this Agreement to ensure the safe operation of the gas pipeline system for GasCo.

(i) UniSource is an Arizona-based company that is well-known, accessible, held in high regard by the community, and experienced in providing quality utility services to Arizona citizens.

(j) Citizens will be able to focus upon its telecommunications business in Arizona consistent with its corporate plan and strategy, in order to foster continued and improved quality of service to Citizens' telecommunications customers in Arizona.

ARTICLE I
INTRODUCTION

1. Purpose of Agreement: Notice of Intentions and Admissions. The Parties agree that the purpose of this Agreement is to resolve contested matters in the Gas Rate Case, the PPFAC Case and the Joint Application in a manner consistent with the public interest. The Parties further recognize that: (1) this Agreement acts as a procedural device to propose its terms to the Commission; (2) this Agreement has no binding force or effect until finally approved by an order of the Commission; and (3) such approval must be given in a timely fashion so that the transaction can close by July 28, 2003. Nothing contained in this Agreement is an admission by any Party that any of the positions taken, or that might be taken by each in this proceeding, is unreasonable or unlawful. In addition, acceptance of this Agreement by any of the Parties is without prejudice to any position taken by any Party in these proceedings.

2. Staff Authority. The Parties recognize that: (1) Staff does not have the power to bind the Commission; and (2) for purposes of settlement, the Staff acts in the same manner as a party in proceedings before the Commission.

3. Commission Authority to Modify. The Parties further recognize that the Commission will evaluate the terms of this Agreement, and that after such evaluation the Commission may require modifications to the terms hereof before accepting this Agreement.

4. Commission Approval. In the event that the Commission adopts an order approving substantially all of the terms of this Agreement, such action by the Commission constitutes approval of the Agreement in a timely fashion so that the transaction can close by July 28, 2003, and thereafter the Parties shall abide by its terms.

5. Effect of Modifications by the Commission. In the event that any signatory Party to this Agreement objects to any modification to the terms of this Agreement made by the Commission, such Party shall timely file an Application for Rehearing under A.R.S. § 40-253. In the event that the Party does not file such an application, that Party shall be deemed: (1) to have accepted the modifications made by the Commission; and (2) to have conclusively and irrefutably accepted that any modifications to the terms of this Agreement are not substantial and therefore the Commission order adopts substantially all of the terms of this Agreement.

6. Effect of an Application for Rehearing. If a signatory Party files an Application for Rehearing that raises objections to any modifications of the terms of this Agreement, then that Party shall be deemed to have withdrawn from this

Agreement. The withdrawing Party shall be relieved of its rights and obligations under this Agreement. The Agreement as modified shall remain in effect and binding upon all of the remaining Parties.

7. Appeal of Commission Decision. If a signatory Party to this Agreement files an Application for Rehearing, which is denied by Commission Order or by operation of law, the Party shall timely file an appeal of the Commission's decision pursuant to A.R.S. § 40-254 or § 40-254.01, as appropriate. In the event that the Party does not file such an appeal, the Party shall be deemed: (1) to have accepted the modifications made by the Commission; and (2) to have conclusively and irrefutably accepted that any modifications to the terms of this Agreement are not substantial, and therefore, the Commission's order adopts substantially all of the terms of this Agreement.

ARTICLE II
TERMS AND CONDITIONS

The Parties to this Agreement hereby agree to the following:

Part A
Transfer of Assets/Certificates and Electric Retail Competition

8. Approval of Transfer of Electric Assets and Certificates. The Parties agree to the transfer of Citizens' Electric Assets to ElecCo, pursuant to A.R.S. § 40-285. The Parties further agree to the transfer of Citizens' CC&N(s) to ElecCo to provide electric utility service in Arizona, and, if required, to the transfer of Citizens' franchises, licenses and other similar authorizations to ElecCo. The Parties further agree that ElecCo will provide copies of such franchises, licenses and other similar authorizations to the Commission within 365 days of Commission approval of this

Agreement. As part of the approval of the transfer of the Electric Assets, ElecCo shall be authorized to recover $1.8 million of the anticipated transaction costs related to the Electric Assets as an offset to the negative acquisition premium so that these costs may be capitalized in accordance with Generally Accepted Accounting Principles ("GAAP").

9. Approval of Transfer of Gas Assets and Certificates. The Parties agree to the transfer of Citizens' Gas Assets to GasCo, pursuant to A.R.S. § 40-285. The Parties further agree to the transfer of Citizens' CC&N(s) to GasCo to provide gas utility service in Arizona, and, if required, to the transfer of Citizens' franchises, licenses and other similar authorizations to GasCo. The Parties further agree that GasCo will provide copies of such franchises, licenses and other similar authorizations to the Commission within 365 days of Commission approval of this Agreement. As part of the approval of the transfer of the Gas Assets, GasCo shall be authorized to recover $2.7 million of the anticipated transaction costs related to the Gas Assets as an offset to the negative acquisition premium so that these costs may be capitalized in accordance with GAAP.

10. Creation of Intermediate Holding Company. The Parties agree that UniSource, at its discretion, may form a holding company ("HoldCo") to finance and to hold ownership in the New Companies.

11. Opening ElecCo's Service Territories to Retail Electric Competition. Within one-hundred twenty (120) days of Commission approval of this Agreement, UniSource shall file for Commission approval a plan to open the ElecCo's service territories to retail electric competition. Topics which shall be addressed include, but

are not limited to the following: (1) unbundled tariffs; (2) system benefits charges; (3) assisting new suppliers in using transmission; and (4) reliability must-run generation ("RMR"). The application shall include an implementation date to open the ElecCo's service territories to competition no later than December 31, 2004. UniSource further agrees to not oppose municipal aggregation in principle as part of any plan to make retail access more likely within ElecCo's service territories.

12. Stranded Costs for ElecCo. UniSource agrees that ElecCo's stranded costs are equal to zero. Stranded Costs, for purposes of this Agreement, are limited to those costs related to generation, which includes those costs related to the purchase power contract between Pinnacle West Capital Corporation ("PWCC") and Citizens implemented on June 1, 2001, as well as all costs related to generation for the generation units in Santa Cruz County.

13. Operational Consolidation of the Santa Cruz Division of ElecCo with TEP. At the time of TEP's next general rate case filing, TEP and UniSource shall submit a feasibility study and written plan for consolidation or, in the alternative, coordination of operations of ElecCo in Santa Cruz County with TEP. The filing shall analyze the ability of TEP to retain two-county bond financing while consolidating the Santa Cruz County operations of ElecCo and TEP; the filing shall also include a comparison of the benefits of the above-described operational consolidation or coordination with the costs of defeasing or redeeming the two-county financing, if there is no ability to retain such two-county financing with the consolidation.

14. Environmental Portfolio Standard ("EPS"). ElecCo and TEP shall cooperate jointly in efforts to comply with the EPS.

15. Incorporation. ElecCo, GasCo and HoldCo shall be incorporated in accordance with the laws of the State of Arizona.

Part B
Financing Provisions

16. Approval of Financing Plan. The Parties agree that the New Companies shall be authorized pursuant to A.R.S. §§ 40-301 *et seq.*, A.R.S. § 40-285 and A.A.C. R14-2-801 *et seq.*, (1) to issue or guarantee up to $175 million of debt securities for the purpose of funding a portion of the purchase price and initial working capital requirements of the New Companies; (2) to issue or guarantee additional debt securities, when appropriate, under the terms of a new revolving credit agreement that shall provide ongoing liquidity support to the New Companies; (3) to enter into indentures or security agreements which grant liens on some or all of the properties held by the New Companies to secure the debt obligations of the New Companies; (4) to issue common stock to UniSource or HoldCo; and (5) to acquire bridge financing. The details of the financing plan are set forth in Appendix A, attached hereto. Approval of the financing plan above is conditioned on TEP agreeing to a loan structure and treatment as follows:

(a) TEP shall be authorized to loan up to $50 million to UniSource ("TEP loan") for the sole purpose of funding the purchase of Citizens' electric utility business and gas utility business. The TEP loan shall not exceed $50 million and shall have a maturity not to exceed four years. The TEP loan shall be secured by UniSource with a pledge of one hundred percent of HoldCo's or the New Companies' common equity. This section is authorized pursuant to A.A.C. R14-2-804.

(b) The fixed annual rate of interest on the TEP loan shall be equal to 383 basis points above the yield-to-maturity on an equivalent four-year United States Treasury Security as determined on the initial date of the loan.

(c) The interest income that TEP receives via the TEP loan to UniSource shall be allocated in the following manner:

(1) 264 basis points of the interest income from the TEP loan shall be recorded as a deferred credit and used to offset rates in the future.

(2) The remaining interest income shall be used toward building the equity capitalization of TEP.

(3) The deferred credit balance shall bear an annual interest rate of six percent.

(d) TEP's ratepayers shall be held harmless from any demonstrable increase in TEP's cost of capital as a result of the TEP loan (including, but not limited to, a decline in bond rating) shown in TEP's next rate case. The effects of any demonstrable increase in TEP's cost of capital as a result of the TEP loan may be considered for offset by any actual demonstrable benefits of the acquisition in establishing the revenue requirement in such future TEP rate cases.

17. Equity Investment in New Companies. The New Companies shall be authorized pursuant to A.R.S. § 40-301 *et seq.*, to issue common stock to UniSource or HoldCo to evidence their ownership interest. To the extent required pursuant to A.A.C. R14-2-803, the Parties agree that UniSource shall be authorized to capitalize the New Companies in the range of $75 million to $125 million.

18. Waiver of Prior Decisions. Decision No. 60480, as amended by the Settlement Agreement adopted in Decision No. 62103, requires UniSource to invest at least thirty (30) percent of the proceeds of a public stock issuance in TEP. The Parties agree that UniSource and TEP shall be granted a waiver of this requirement for the sole purpose of financing the acquisition of Citizens' Electric Assets and Gas Assets as set forth in this Agreement and in the Joint Application by UniSource and Citizens.

19. Capital Structure of ElecCo and GasCo. UniSource agrees that until such time as GasCo's equity capitalization equals forty (40) percent of total capital, GasCo will not issue dividends to either HoldCo and/or UniSource which comprise more than seventy-five (75) percent of GasCo's earnings. UniSource further agrees that until such time as ElecCo's equity capitalization equals forty (40) percent of total capital, ElecCo will not issue dividends to either HoldCo and/or UniSource which comprise more than seventy-five (75) percent of ElecCo's earnings. For purposes of this provision, the common equity ratio shall be calculated by dividing the common equity by the sum of such common equity, preferred equity and long-term debt (including current maturities of such debt). Either ElecCo or GasCo may apply for a

waiver of this provision, which shall be processed within sixty (60) days of such application and where this provision may be suspended up to sixty (60) days.

20. Capital Structure of TEP. UniSource agrees that until such time as TEP's equity capitalization equals forty (40) percent of total capital, TEP shall not issue dividends to UniSource which comprise more than seventy-five (75) percent of TEP's earnings. This change shall serve as a modification to Commission Decision No. 60480, Attachment A, Condition 20, which was the Commission Decision that established UniSource as a holding company for TEP. For purposes of this provision, the common equity ratio shall be calculated by dividing the common equity by the sum of such common equity, preferred equity and long-term debt (including current maturities of such debt). TEP may apply for a waiver of this provision, which shall be processed within sixty (60) days of such application and where this provision may be suspended up to sixty (60) days.

Part C
Citizens Gas Division/GasCo Rate Case

For purposes of this part, Appendix B, which contains schedules in support of this Agreement, is incorporated herein as part of this Agreement.

21. Fair Value Rate Base. For ratemaking purposes and for purposes of this Agreement, the Parties agree to a Fair Value Rate Base ("FVRB") Number of $142,132,013 as of October 29, 2002. See Appendix B, Schedule 2.

22. Rate of Return. For ratemaking purposes and for purposes of this Agreement, the Parties agree that a reasonable rate of return on the FVRB equals 7.49 percent. This number is based on a cost of capital of 9.05 percent, which is further based on a cost of equity of 11.00 percent and a cost of debt of 7.75 percent for

original cost rate base. This agreed upon rate of return on FVRB is the result of negotiation. See Appendix B, Schedule 1.

24. Revenue Requirement. For ratemaking purposes and for purposes of this Agreement, the Parties agree that GasCo's increase in revenue requirement equals $15,191,276. See Appendix B, Schedule 1.

25. Rate Design. The Parties agree to the rate design attached hereto as Appendix B, Schedule 3 and incorporated herein by this reference. The rate design includes the following provisions.

(a) A monthly customer service charge equaling $7.00 for all residential customers. This represents an increase of $2.00 to the monthly service charge of $5.00.

(b) A base cost of gas implicit in the commodity rates for all tariff classes shall be $0.400 per therm.

26. Purchase Gas Adjustor ("PGA"). The Parties agree that the PGA bank balance shall not be affected by this Agreement and that UniSource and/or GasCo shall abide by previous Commission orders regarding treatment of the PGA bank balance. The Parties further agree that GasCo shall abide by all Commission requirements when seeking recovery of any amounts in the PGA bank balance and/or establishing a surcharge to recover such amounts. In connection with the implementation of the new $0.400 per therm base cost of gas, the existing limitation of $0.100 per therm over twelve months within which the PGA rate may now fluctuate without formal Commission approval, shall be increased to $0.150 per therm for a period of twelve consecutive months, beginning with the first calendar

month after Commission approval of this Agreement. At the end of the twelve consecutive months, the PGA rate shall revert to the previous $0.100 per therm over twelve months limitation.

<u>Part D</u>
<u>Electric Purchase Power & Fuel Adjustor Clause ("PPFAC")</u>

27. <u>PPFAC Balance, Base Rate for Purchase Power, and the Adjustor Rate for Purchase Power</u>. The Parties agree that effective from the date of the closing of the purchase of Citizens' electric utility assets, the adjustor rate shall be set at $0.01825 per kilowatt hour ("kWh"). The base rate for purchase power shall remain at $0.05194 per kWh. The total cost for purchase power shall equal the base rate plus the adjustor rate, or $0.07019 per kWh. The composition of the total cost for purchase power is set forth in the attached Appendix C. UniSource, any of its subsidiaries, and Citizens shall forfeit their right to pursue recovery from retail ratepayers of the PPFAC balance existing prior to and including the date of closing.

28. <u>Renegotiation of the PWCC Contract</u>. This provision refers to the purchase power contract signed by Citizens and PWCC on June 1, 2001. UniSource agrees that it shall, in good faith, attempt to renegotiate the PWCC Contract. Any and all savings from any successfully renegotiated purchase power contract with PWCC and/or any amendment to the existing purchase power contract with PWCC shall be shared between ElecCo's customers and UniSource. Sixty (60) percent of the savings shall go directly towards the benefit of ElecCo's ratepayers and forty (40) percent of the savings shall go to UniSource. The above-described sharing from renegotiating the PWCC contract and/or amending the existing PWCC contract shall

only apply for the duration of the existing or renegotiated PWCC contract, whichever duration would expire sooner. Once that timeframe expires, any and all savings shall be passed through directly to ElecCo's customers.

Part E
Pipeline Safety Provisions

29. Staffing of Safety Personnel. UniSource shall not allow the acquisition to diminish staffing that would result in service and/or safety degradation in either of the current Citizens Arizona Gas Division sections, Northern Arizona Gas Division ("NAGD") or Citizens Santa Cruz Gas Division ("SCGD"), service territories.

30. Maintaining Field Offices. UniSource shall continue to maintain fully operational current local field offices in the NAGD and SCGD service territories, as appropriate, to maintain the quality of service and ensure pipeline safety.

31. Not Using Contract Personnel for Operations and Maintenance Duties. UniSource shall continue Citizens Arizona Gas Division's current practice of not using contract personnel for the performance of operation and maintenance functions, such as, leak survey and valve maintenance.

32. Adopting Citizens' Gas Divisions Operations and Maintenance Procedures for GasCo. UniSource shall adopt the most recent version of Citizens Arizona Gas Division's operations and maintenance manuals and procedures, including but not limited to the emergency plan, and agrees to make revisions and additions to only those specific sections as necessary. Such section updates shall be provided to the Commission's Chief of the Office of Pipeline Safety ("OPS").

33. Quality of Service. UniSource shall use all commercially reasonable efforts to prevent the quality of service in either of the current Citizens Arizona gas

divisions (NAGD or SCGD) service territories from diminishing as a result of the acquisition. The number of service complaints, the response time to service complaints and service interruptions should not increase as a result of the acquisition.

34. Inspection of Installation by Contract Personnel. With regard to the installation of new service lines and main extensions on the acquired gas system, GasCo's personnel shall independently inspect any and all work done by any contract personnel on any and all portions of either of the acquired gas division sections.

Part F
Miscellaneous Provisions

35. Negative Acquisition Adjustment. UniSource agrees that it shall permanently credit customers for the negative acquisition adjustments of $30,700,000 for GasCo and $93,624,000 for ElecCo, cited in Appendix B, Schedule 1 and Appendix B, Schedule 4 respectively, until fully amortized over the life of the plant related to this Agreement and that it shall not seek any other treatment. As a result, the net plant in service for the electric system purchased by UniSource shall be $93,800,000 as of October 29, 2002. See Appendix B, Schedule 4. UniSource agrees that the negative acquisition adjustments shall be initially recorded as a credit in FERC Account 114; Gas Plant Acquisition Adjustments and Electric Plant Acquisition Adjustments, respectively. Upon completion of the transaction and final accounting, GasCo and ElecCo shall transfer the amounts in FERC Account 114, Gas/Electric Plant Acquisition Adjustments, to FERC Account 108, Accumulated Provision for Depreciation of Gas/Electric Utility Plant. GasCo and ElecCo shall then establish sub-accounts to FERC Account 108 to record an allocation of the total negative acquisition adjustment to each FERC plant account. The sub-accounts shall

be amortized at the same rates as the depreciation rates for the corresponding plant accounts. The amortization of the negative acquisition adjustment shall be recorded as a debit to FERC Account 108 and a credit to account 406 (Amortization of Gas/Electric Plant Acquisition Adjustments), and shall reduce the depreciation expense included in the cost of service for recovery in rates. The negative acquisition balance shall reduce rate base included in cost of service for recovery in rates until fully amortized.

36. Prudency Reviews.

(a) The Parties agree that the Commission shall not conduct any prudency reviews of Citizens' gas procurement practices, accounting practices or balances existing on or before October 29, 2002.

(b) In Decision No. 57647, the Commission required Citizens to conduct a buildout program (the "Buildout Program"). The Commission approved the proposed Buildout Program in Decision No. 58664. The Parties agree that the Commission shall not conduct any further prudency reviews of the Buildout Program beyond the $10 million reduction currently incorporated into the gas rate base figures set forth in Article II, Part C of this Agreement. The $10 million reduction is a disallowance from gas rate base that shall be a permanent write-down of plant as an adjustment to the gas rate base due to a prudence review of the Buildout Program.

37. Additional Acquisition Costs. The Parties agree that ElecCo's ratepayers shall be held harmless from any recovery directly related to the increase in acquisition costs that will result under Section 3.3(a)(iii) of the Electric Asset Purchase Agreement if the transaction closes after October 29, 2003. The Parties

further agree that GasCo's ratepayers shall be held harmless from any recovery directly related to the increase in acquisition costs that will result under Section 3.3(a)(iii) of the Gas Asset Purchase Agreement if the transaction closes after October 29, 2003.

38. Capital Expenditures. The Parties agree that work orders closed after October 29, 2002 through the date of closing of the transaction related to the Electric Assets and the Gas Assets shall be included in the rate base for ElecCo and GasCo (subject to prudency review) on a dollar-for-dollar basis (*i.e.*, not reduced by the negative acquisition adjustment) in the next rate filing.

39. Rate Moratorium. The Parties agree that neither GasCo nor ElecCo shall file a general rate case for a period of three years from the date of the Commission order approving substantially all of the terms of this Agreement; provided, however, that GasCo and ElecCo shall not be prohibited from seeking a change in rates in the event of: (a) conditions or circumstances that constitute an emergency; or (b) material changes to the cost of service resulting from federal, tribal, state or local laws, regulatory requirements, judicial decisions, actions or orders.

40. Revised Line Extension Tariff and Policy. The Parties agree that GasCo's revised gas facilities service line and main extension tariff of the Arizona gas utility, incorporated herein as Appendix D, may be amended and implemented upon Commission approval of this Agreement.

41. Approval Limitation. UniSource must re-apply with the Commission for approval of this Agreement and the Joint Application if the deal is not

consummated within six months of Commission approval of this Agreement. UniSource may apply for an extension of six-month time limitation where it will be the burden of UniSource to demonstrate why the merger agreement was not consummated and why approval of the extension is in the public interest.

42. Tariff Filings. UniSource will file, within thirty (30) days of Commission approval of this Agreement, tariffs reflecting all Commission-approved changes contained in the gas rate case filing. Tariffs will be effective from the date of closing of the purchase of Citizens' electric utility and gas utility assets. Within sixty (60) days of Commission approval of this Agreement, UniSource shall file an application for Commission approval of tariffs specifically regarding the negotiated sales program and gas transportation issues.

43. Notice to Customers. Following Commission approval of this Agreement and consummation of the transactions set forth in the Joint Application, UniSource will provide in bills sent to applicable customers of the New Companies a notice regarding the revised rates, terms and conditions or service as set forth in this Agreement. UniSource shall provide such notification to the New Companies' customers within sixty (60) days of approval of this Agreement of the rates and charges authorized by this Agreement and the effective date of same. The bill inserts shall also inform consumers that the Commission remains the regulatory agency responsible for overseeing the terms, conditions, rates and quality of service provided by the New Companies. Finally, the bill inserts shall inform consumers that any complaints regarding any of the New Companies regulated services that cannot be

resolved by the New Companies may be directed to the Commission's Consumer Services Section.

44. Limitations. This Agreement represents the Parties' mutual desire to compromise and settle disputed claims and issues regarding the issues set forth in the Consolidated Cases in a manner consistent with the public interest and based upon the pre-filed testimony, exhibits and evidentiary record developed in the Consolidated Cases and represents a compromise of the positions of the Parties. The terms and provisions of this Agreement apply solely to and are binding only in the context of the provisions and results of this Agreement and none of the positions taken in this Agreement by any of the Parties may be referred to, cited to, or relied upon by any other Party in any fashion as precedent or otherwise in any proceeding before the Commission or any other regulatory agency or before any court of law for any purpose except in furtherance of the purpose and results of this Agreement.

45. Privileged and Confidential Communications. All negotiations relating to or leading to this Agreement are privileged and confidential and no Party is bound by any position asserted in negotiations, except to the extent expressly stated in this Agreement. Evidence of conduct or statements made in the course of negotiation of this Agreement are not admissible as evidence in any proceeding before the Commission, any other regulatory agency or any court.

46. Force Majeure. Parties to this Agreement shall be excused for delays or failure in performance under this Agreement caused by acts of God, war, strike, labor dispute, work stoppage, fire, act of government, or any other cause, whether similar or dissimilar, beyond the reasonable control of that Party. The Parties agree

that if any of the above-described conditions occur, such that a Party that is a signatory to this Agreement cannot fulfill its obligations under this Agreement, that Party shall notify the other Parties and shall pursue an amendment or modification to this Agreement and/or the Commission order approving this Agreement in accordance with A.R.S. § 40-252.

47. Definitive Text. The "Definitive Text" of this Agreement shall be the text adopted by the Commission in an order adopting substantially all of the terms of this Agreement including all modifications made by the Commission in such order.

48. Severability. Each of the terms of the Definitive Text of this Agreement is in consideration and support of all other terms. Accordingly, the terms are not severable.

49. Support and Defend. The Parties pledge to support and defend this Agreement before the Commission. If this Agreement enters into force the Parties will support and defend this Agreement before any court or regulatory agency in which it may be an issue.

[SIGNATURES APPEAR ON NEXT PAGE]

STAFF OF THE UTILITIES DIVISION OF THE ARIZONA CORPORATION COMMISSION

By:
Title:

Signature:____________________________

Date: ____________________________

UNISOURCE ENERGY CORPORATION

By: James S. Pignatelli
Title: CEO

Signature:

Date: March 31, 2003

TUCSON ELECTRIC POWER

By: James S. Pignatelli
Title: CEO

Signature:

Date: March 31, 2003

CITIZENS COMMUNICATIONS COMPANY

By:
Title:

Signature:____________________________

Date: ____________________________

STAFF OF THE UTILITIES DIVISION OF THE ARIZONA CORPORATION COMMISSION

By:
Title:

Signature:______________________________

Date: ______________________________

UNISOURCE ENERGY CORPORATION

By:
Title:

Signature:______________________________

Date: ______________________________

TUCSON ELECTRIC POWER

By:
Title:

Signature:______________________________

Date: ______________________________

CITIZENS COMMUNICATIONS COMPANY

By: Daniel McCarthy
Title: President 9CCO Public Services

Signature:______________________________

Date: 3/31/03

STAFF OF THE UTILITIES DIVISION OF THE ARIZONA CORPORATION COMMISSION

By: Ernest G. Johnson
Title: Utilities Director

Signature: E G. Johnson

Date: 4-1-03

UNISOURCE ENERGY CORPORATION

By:
Title:

Signature:_________________________

Date: _________________________

TUCSON ELECTRIC POWER

By:
Title:

Signature:_________________________

Date: _________________________

CITIZENS COMMUNICATIONS COMPANY

By:
Title:

Signature:_________________________

Date: _________________________

APPENDIX A

Financing Plan

A. <u>Debt Issuance by New Companies</u>

1. Bridge Financing. Depending on market conditions, it may be necessary or desirable for either HoldCo or the New Companies to initially issue or guarantee Debt Securities to fund the purchase price on an interim basis and, following the closing of the purchase, to refinance such bridge financing on a more permanent basis. If such bridge financing is utilized, it is anticipated that either HoldCo or the New Companies would enter into a credit or other financing agreement with commercial banks or other institutional lenders for this purpose. The aggregate amount of Debt Securities to be issued under the bridge financing would not exceed $250 million.

Interest. Variable rates based on rates prevailing in the market.

Maturity Date. Not to exceed three years.

Security. In the event that security for the loans is necessary or desirable, each of the New Companies may secure its obligations with a mortgage lien on some or all of the properties acquired from Citizens and other properties of the New Companies.

2. Bond Financing. In order to fund the acquisition, or to refinance any bridge financing described above, the New Companies may issue or guarantee long-term Debt Securities in the capital markets ("Bonds"). The aggregate principal amount of Bonds issued to fund the acquisition or refinance a bridge facility would not exceed $175 million.

Interest. Fixed interest rate based on rates prevailing in the market at the time of issuance.

Maturity Date. Not to exceed thirty years.

Security. In the event that security for the Bonds is necessary or desirable, each of the New Companies may secure its Bonds with a mortgage lien on some or all of the properties acquired from Citizens and other properties of the New Companies.

Collateral Trust Bonds. Should the Bonds be issued by HoldCo on a secured basis, the Bonds may be issued as collateral trust bonds secured by mortgage bonds to be issued by either or both of the New Companies. The New Company mortgage bonds would have the same principal amount, stated rate of interest and maturity date as the HoldCo bonds, and would be held in trust as collateral for the HoldCo bonds. If the Bonds are issued on an unsecured basis, covenants may be required that would restrict or prohibit the issuance of secured debt so long as any unsecured bonds remain outstanding.

B. **Revolving Credit Financing**. For the purpose of obtaining short-term liquidity support, each or both of the New Companies may enter into a revolving credit agreement with commercial banks and other institutional lenders. Under such agreement, or one entered into by HoldCo on behalf of the operating companies, the New Companies may issue up to $50 million of Debt Securities at any given time as evidence of loans under the agreement.

Interest. Variable rates based on rates prevailing in the market.

Maturity Date. Not to exceed fives years.

Security. In the event that security for the loans is necessary or desirable, each of the New Companies may secure the loans with a mortgage lien on some or all of the properties acquired from Citizens and other properties of the New Companies.

C. UniSource Equity Investment

UniSource shall be authorized to make an equity investment in the New Companies in the range of $75 million-$125 million. As described in Settlement Agreement, up to $50 million of this equity investment may be financed through a TEP loan to UniSource. The balance of the equity investment would come from general corporate funds available to UniSource. UniSource may issue new common stock to help fund the acquisition and/or to pay off interim financing or other contributions by UniSource. Upon receipt of this equity investment, the New Companies would issue common stock to UniSource or HoldCo to evidence their ownership interest.

UniSource Acquisition of Citizens Utility
2001 Test Year

Line No.	Description	Citizens Original Cost Rate Base	UniSource As Filed	UniSource Settlement
1	Gross Utility Plant in Service (w/CIAC)	$219,383,559	$219,383,559	$219,383,559
2	Accumulated Depreciation	($53,751,970)	($53,751,970)	($53,751,970)
3	*Adjustment for Purchase*		($30,709,737)	($30,709,737)
4	Adjustment to the Build Out Program			($10,000,000)
5	Net Utility Plant in Service	$165,631,589	$134,921,852	$124,921,852
6	*Accumulated Deferred Income Taxes*	($5,713,762)		
7	Advances for Construction	($6,395,371)	($6,395,371)	($6,395,371)
8	Customer Deposits	($1,812,850)	($1,812,850)	($1,812,850)
9	Materials and Supplies	$968,581	$968,581	$968,581
10	Warm Spirit	($40,001)	($40,001)	($40,001)
11	Cares	($364,946)	($364,946)	($364,946)
12	Sale of Office Buildings	($104,431)		
13	Y2K Costs	$383,765	$383,765	$383,765
14	Allowance for Working Capital	($2,924,219)		
15	Total Rate Base	$149,628,355	$127,661,030	$117,661,030
16	Total Return	$13,242,109	$11,553,323	$10,648,323
17	Operating Expenses	$29,859,583	$28,883,183	$28,883,183
18	Income Taxes	$5,426,078	$3,703,569	$3,413,459
19	Proposed Revenue	$48,531,496	$44,140,075	$42,944,966
20	Proposed (Required) Operating Income	$13,245,835	$11,553,323	$10,648,323
20	Current Operating Income	$554,855	$1,499,758	$1,499,758
21	Proposed Increase in Operating Income	$12,687,254	$10,053,565	$9,148,565
22	Gross Revenue Conversion Factor	1.656	1.656	1.656
23	Increase in Gross Revenue	$21,005,521	$16,645,370	$15,146,990
24	Depreciation Adjustment for Build Out Reduction			($272,000)
25	Reversal of Taxes on Debt for Build Out Reduction			$304,886
26	Adjustment for Difference Regarding Debt for Build Out Reduction			$11,400
27	Increase in Gross Revenue with all Build Out Adjustme	$21,005,521	$16,645,370	**$15,191,276**
28	Test Year Gross Revenue	$72,610,605	$72,610,605	$72,610,605
29	Percent Increase over Present Rates	28.93%	22.92%	20.92%

UniSource's Cost of Capital-Settlement

	Cost	Weight	WACC
Debt	7.75%	60.00%	4.65%
Equity	11.00%	40.00%	4.40%
			9.05%

Citizen's Cost of Capital

	Cost	Weight	WACC
Debt	6.70%	50.00%	3.35%
Equity	11.00%	50.00%	5.50%
			8.85%

UNS Filed Equity Return	Settlement Equity Return
$5,617,085	$5,177,085

UNISOURCE ENERGY SERVICES
SETTLEMENT AGREEMENT
GAS RATE CASE - 2001

Line No.	Description	ORIGINAL COST	FAIR VALUE
1	Adjusted Rate Base	$117,661,030	142,132,013
2	Adjusted Operating Income	$1,499,758	$1,499,758
3	Current Rate of Return	1.27%	1.06%
4	Required Operating Income	$10,648,323	$10,648,323
5	Required Rate of Return	9.05%	7.49%

Citizens Communications Company

Arizona Gas Division

NATURAL GAS RATES
SUMMARY OF FILED TARIFFS

PROPOSED RATES

Rate Designation	Rate Description	Customer Charge	Margin	Gas Cost	Basic Cost of Service Rate
R-10	Residential	$ 7.00	$ 0.3004	$ 0.4000	$ 0.7004
R-12	CARES - $0.15 Discount (Nov - Apr)	$ 7.00	$ 0.1504	$ 0.4000	$ 0.5504
C-20	Small Volume Commercial	$ 11.00	$ 0.2420	$ 0.4000	$ 0.6420
C-22	Large Vol. Commerical	$ 85.00	$ 0.1551	$ 0.4000	$ 0.5551
I-30	Small Volume Industrial	$ 11.00	$ 0.2122	$ 0.4000	$ 0.6122
I-32	Large Vol. Industrial	$ 85.00	$ 0.0864	$ 0.4000	$ 0.4864
PA-40	Small Vol. Public Authority	$ 11.00	$ 0.2354	$ 0.4000	$ 0.6354
PA-42	Lg. Vol. Public Authority	$ 85.00	$ 0.1084	$ 0.4000	$ 0.5084
PA-44	Special Gas Light Service	various			
IR-60	Irrigation Service	$ 11.00	$ 0.2876	$ 0.4000	$ 0.6876
T-1	Transportation	Otherwise applicable base rates less embedded gas costs			
T-2	Dedicated Transportation	Cost to service + subsidies (Including $95 Customer Charge)			
CNG-1	Compressed Natural Gas	various			
EC-1	Electric Cogeneration	$ 85.00	$ 0.0488	$ 0.4000	$ 0.4488
CGS-1	Competitive Gas	negotiated			
NSP-1	Negotiated Sales Program	negotiated			
MISC-1	Miscellaneous Tariffs	various			

NOTES:

1 Only primary rates are shown when multiple blocks are present.

UniSource Acquisition of Citizens Utility
Net Electric Utility Plant In Service
At 10/29/02

Line No.	Description	Citizens Original Cost Rate Base	UniSource Settlement
1	Gross Utility Plant in Service *(incl. CIAC)*	$299,425,000	$299,425,000
2	Accumulated Depreciation	($112,001,000)	($112,001,000)
3	Adjustment for Purchase		($93,624,000)
4	Net Utility Plant in Service	$187,424,000	$93,800,000

UNISOURCE ENERGY CORPORATION **APPENDIX C**

PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE
RATE COMPONENTS

		$/kWh	
Current PPFAC Base Rate			
Cost of Electric Generation		$0.04802	\1
Cost of WAPA Transmission		$0.00392	\1
Total Current Rate		$0.05194	
Increase in Cost of Generation			
APS contract cost of generation (a)	(a)	$0.05879	\1
Loss Factor (b)	(b)	10.69%	\1, \2
Cost of Electric Generation at Meter	a / (1 - b)	$0.06583	
Increase in Cost of Generation		$0.01781	
Increase in WAPA Transmission			
Increase in WAPA Transmission		$0.00044	\1
Current Cost of WAPA Transmission		$0.00436	\1
PPFAC Adjustor Rate		**$0.01825**	

\1 Citizens' Amended Application for the Purchased Power and Fuel Adjustment Clause dated September 19, 2001.
\2 Approved Losses Rate from Citizens' last rate case.

PROPOSED SECTION NO. 7
EXTENSION OF LINES

Extensions of gas distribution services and mains necessary to furnish permanent service to applicants will be made in accordance with this rule.

A. GENERAL

The Utility will construct, own, operate and maintain service and main line extensions.

1. Gas service lines will be of suitable capacity from the Utility's gas main to a meter location on the property of the applicant that is satisfactory to the Utility

2. Gas distribution main extensions will be only along public streets, roads, and highways, which the Utility has legal right to occupy, and on public lands and private property across which rights-of-way, satisfactory to the Utility, may be obtained.

B. SERVICE AND MAIN EXTENSIONS TO APPLICANTS FOR SERVICE

1. General Policy – All service line and main line extensions are made on the basis of economic feasibility except those for master-metered mobile home parks (MMP), whose extensions shall be made in accordance with the provisions in Section B.3 hereof. The economic feasibility will be calculated by the Incremental Contribution Method as described in Section B.4 hereof. However, at a minimum, the Utility will extend 30 feet of main for each applicant who connects a functioning water heater or furnace within 4 months of the completion of the main.

2. Facility Charge – If any applicant fails to use natural gas for equipment stated in the application and used as the basis for estimating the allowable investment within 4 months of the completion of the main, the Utility may calculate and bill the applicant and the applicant shall pay within 45 days a nonrefundable Facilities Charge according to the Utility's extension rule in effect at the time the extension was made as though service had been requested on the basis of the actual equipment installed and utilized. At its option, the Utility may require a performance bond or other surety guaranteeing bona fide operation of the facility for which the extension is requested in accordance with applicant's representation in the contract.

3. If the residential customers are tenants in a fully improved MMP and the MMP is currently or was formerly served as a master-metered mobile home park, the allowable investment for the MMP will be determined by the following formula:

$$AI = (FR - CR) \times 5$$

where:

AI = Allowable Investment

FR = The MMP's estimated future total annual revenue, assuming conversion to individual residential service, using the MMP's average park occupancy for the past two years, less the Utility's current average cost of purchased gas.

CR = The MMP's current total annual revenue, under the applicable schedule, averaged for the past two years, less the Utility's current average cost of purchased gas. If the MMP is not a current customer of the Utility, the CR will be determined on the basis of engineering estimates of occupancy and usage.

The Utility will install that portion of each service in excess of the allowance subject to a nonrefundable contribution to be paid prior to construction by the applicant MMP. In no event shall costs above the allowable investment be borne by the Utility.

4. Incremental Contribution Method – Gas service line and main line extensions will be made by the Utility at its expense for the allowable investment as calculated by an Incremental Contribution Study (ICS).

   a. Allowable investment shall mean a determination by the Utility that the revenues less the incremental gas cost to serve the applicant customer provides a rate of return on the Utility's investment no greater than the most recent overall rate of return authorized by the Commission in a general rate case for the Utility.

   b. All applicants will pay for the entire length of their service lines on their property. If the ICS has an allowable investment that is more than the cost of the main extension, then the excess will be applied evenly to all applicants to reduce their cost of service line installation.

   c. The Utility, after conducting an ICS, may at its option, extend its facilities to Customers whose usage does not satisfy the definition of Economic Feasibility but who otherwise are Permanent Customers provided such Customer signs an extension agreement and advances as much of the cost, and/or agrees to pay a nonrefundable Facility Charge necessary to make the extension economically feasible.

   d. Applicants may provide trench for service lines and/or mains to the Utility's specifications and the Utility costs will be reduced by an amount equal to this avoided cost in the ICS.

   e. Customers provided with line extensions using the Incremental Contribution Method shall be reviewed annually for a period of five years to determine the amount of any refund as described in Section B5.

5. Method of Refund

Amounts advanced by the customer(s) in accordance with this rule, less any unpaid Facility Charges, shall be refunded, without interest, in the following manner.

a. Refunds of an advance shall be made for each additional separately metered permanent service connected to the main extension for which an advance was collected when an excess allowable investment is calculated by an ICS that includes the additional customers(s). The calculation will use actual usage for existing customers. Future years usage will be estimated on actual usage adjusted for normal weather.

b. Customers adding on to an existing main covered by an extension agreement, still subject to refund, will pay the entire cost of their service line, will contribute an advance equal to the average advance, minus any refunds, provided by the existing contributors, and will be eligible for refunds of advances in subsequent annual reviews.

c. No refunds will be made for additional customers connecting to a further extension or series of extensions constructed beyond the original extension.

d. Refunds will be made annually or intermittently within the annual period at the option of the Utility. Amounts to be refunded may be accumulated by the Utility to a maximum of $50 per customer, or the total refundable balance if less than $50 per customer. Refunds will only be made to customers, the assignees of customers, or developers.

e. When two or more parties make a joint advance on the same extension, refundable amounts will be distributed to these parties in the same proportion as their individual percentages of the total joint advance.

f. The refund period shall be five years from the date of the completion of the extension. No refunds will be made by the Utility after the termination of the refund period. Any portion of the advance that remains unrefunded at the end of the refund period shall remain the property of the Utility.

g. Any assignment by a customer of their interest in any part of an advance, which at the time remains unrefunded, must be made in writing and approved by the Utility.

h. Amounts advanced under a gas main extension rule previously in effect will be refunded in accordance with the provisions of such rule.

C. SERVICE AND MAIN EXTENSIONS TO SERVE INDIVIDUALLY-METERED SUBDIVISIONS, TRACTS, HOUSING PROJECTS, MULTI-FAMILY DWELLINGS AND MOBILE HOME PARKS OR ESTATES

1. Advances

a. Gas distribution service and main extensions to and within individually metered subdivisions, housing projects, multi-family dwellings and mobile home parks or estates will be constructed, owned and maintained by the Utility in advance of applications for service by bona fide customers only when the entire estimated cost of such extensions as determined by the Utility is advanced to the Utility, and a main extension contract is executed. This advance may include the cost of any gas facilities installed at the Utility's expense in conjunction with a previous service or main extension in anticipation of the current extension.

b. When a subdivider/builder/developer is building a project in consecutive phases such that each phase is constructed separately and requires separate advances, unused allowances from one phase may be applied to an outstanding advance in any other phase so long as such outstanding advance is still eligible for refund.

c. For developers who have entered into a line extension agreement and facilities have been installed and then they or some other party request subsequent reconfiguring of facilities or other changes requiring additional expenditures by the Utility, these new costs will be entirely paid for with a non-refundable advance and any refunds will be made in accordance with the original agreement. No additional agreement or extension of the time for refunds will be made to cover the area piped under the original extension agreement.

d. See, Section B3 for governing requests to serve MMP through individual residential meters if the MMP is currently or was formerly served under a MMP schedule.

e. Refunds will be made to developers as described in Section B5.

D. GENERAL CONDITIONS

1. Postponement of Advance

The Utility, at its option, may postpone, for a period not to exceed five years, that portion of an advance which it estimates would be refunded under the provisions of this rule. At the end of such refund period, the Utility shall collect all such amounts not previously advanced which were not then refundable. When advances are postponed, the applicant may be required to furnish to the Utility evidence of the necessary approvals to commence construction and of adequate financing. A surety bond satisfactory to the Company, or other Utility-approved surety, may be required to assure payment of any postponed amounts at the end of the postponement period.

2. The applicants or developer will provide property location, tax-identification numbers and other property information helpful to planning an extension.

3. Contracts

a. Each applicant requesting an extension in advance of applications for service will be required to execute a contract covering the terms under which the Utility will install main lines in accordance with the provisions of the tariff schedules.

b. At the time service is requested, the applicant will submit a list of natural gas equipment to be used including the Btu input.

4. One Service for a Single Premise

   a. The Utility will not install more than one service line to supply a single premise, unless it is for the convenience of the Utility or an applicant requests an additional service, and in the opinion of the Utility, an unreasonable burden would be placed on the applicant if the additional service were denied. When an additional service is installed at the applicant's request, the applicant shall make a nonrefundable contribution for the additional service based on the Utility's estimated cost.

   b. When a service extension is made to a meter location upon private property which is subsequently subdivided into separate premises, with the ownership portions thereof divested to other than the applicant or the customers, the Utility shall have the right, upon written notice, to discontinue service without obligation or liability. Gas service, as required by said applicant or customer, will be reestablished in accordance with the applicable provisions of the Utility's rules.

5. Branch Services

   The Utility, at its option, may install a branch service for units on adjoining premises.

6. Main Extension Agreement Requirements

   a. Upon request by an applicant for a main extension, the Utility shall prepare, without charge, a preliminary sketch and rough estimate of the cost of the installation to be advanced by the applicant.

   b. Any applicant for a main extension requesting the Utility to prepare detailed plans, specifications, or cost estimates may be required to deposit with the Utility an amount equal to the estimated cost of preparation. The Utility shall, upon request, make available within 90 days after receipt of the deposit referred to above, such plans, specifications, or cost estimates of the proposed main extension. Where the applicant authorizes the Utility to proceed with the construction of the extension, the deposit shall be credited to the cost of construction; otherwise, the deposit shall be nonrefundable. If the extension is to include oversizing of facilities to be done at the Utility's expense, appropriate details shall be set forth in the plans, specifications and cost estimates. Subdividers providing the Utility with approved plans shall be provided with plans, specifications or cost estimates within 45 days after receipt of the deposit referred to above.

   c. Where the Utility requires an applicant to advance funds for a main extension, the Utility shall furnish the applicant with a copy of this rule prior to the applicant's acceptance of the Utility's extension agreement.

   d. All main extension agreements requiring payment by the applicant shall be in writing, signed by each party and shall include the following.

      (1) Name and address of applicant(s).

      (2) Proposed service address(es) or location(s).

(3) Description and sketch of the requested main extension.

(4) Description of requested service.

(5) A cost estimate to include materials, labor, and other costs as necessary.

(6) Payment terms.

(7) A concise explanation of any refunding provisions, if applicable.

(8) The Utility's estimated start date and completion date for construction of the main extension.

(9) A summary of the results of the Incremental Contribution analysis performed by the Utility to determine the amount of advance required from the applicant for the proposed main extensions.

(10) Each applicant shall be provided a copy of the approved main extension agreements.

7. Relocation of Services and Mains

a. When, in the judgment of the Utility, the relocation of a main or service is necessary and is due either to maintenance of adequate service or the operating convenience of the Utility, the Utility shall perform such work at its own expense.

b. If relocation of a main or service line is due solely to meet the convenience or the requirements of the applicant or the customer, such relocation, including metering and regulating facilities, shall be performed by the Utility at the expense of the applicant or the customer.

c. Relocation of facilities will be mandatory and at the customer's expense when actions of the customer restrict the Utility's access to or the safety of the facility.

8. Standby Service or Residential Pool Heating

No allowance will be made for equipment used for standby or emergency purposes only.

9. Temporary Service

Extensions for temporary service or for operations, which in the opinion of the Utility are of a speculative character or of questionable permanency will will require an advance for the entire cost of the facilities required, with provision for a refund with the use of an ICS calculated annually or at the termination of the temporary service.

10. Length and Location

The length of main or service required for an extension will be considered as the distance along the shortest practical and available route, as determined by the Utility, from the Utility's nearest permanent distribution main.

11. Service Impairment to Other Customers

When, in the judgment of the Utility, providing service to an applicant would impair service to other customers, the cost of necessary reinforcement to eliminate such impairment may be included in the cost calculation for the extension.

12. Service From Transmission Lines

The Utility will not tap a gas transmission main except when conditions in its sole opinion justify such a tap. Where such taps are made, the applicant will pay the Utility the cost of such tap, and extensions therefrom will be made in accordance with the provisions of this rule.

13. Other Types of Connections

Where an applicant or customer requests a type of service connection other than standard such as curb meters and vaults, etc., the Utility will consider each such request and will grant such reasonable allowance as it may determine. The Utility shall install only those facilities that it determines are necessary to provide standard natural gas service in accordance with this tariff. Where the applicant requests the Utility to install special facilities which are in addition to, or in substitution for, or which result in higher costs than the standard facilities which the Utility would normally install, the extra cost thereof shall be borne by the applicant.

14. Excess Flow Valve Installation Option

In accordance with Title 49, Section 192.383 of the Code of Federal Regulations, the installation of an excess flow valve, as defined in Rule No. 1, shall be performed by the Utility on a new or replaced single residence service line at the request of a customer. The installation of an excess flow valve is not mandatory; if a customer elects this installation, the Utility shall perform the installation subject to the customer assuming responsibility for all costs associated with installation, maintenance and replacement. Each customer requesting the installation of an excess flow valve will be required to execute a written agreement.

15. Exceptional Cases

In unusual circumstances, when the application of this rule appears impractical or unjust to either party, the Utility or the applicant may refer the matter to the Commission for special ruling or for the approval of special conditions which may be mutually agreed upon, prior to commencing construction.

16. Taxes Associated with Nonrefundable Contributions and Advances

Any federal, state or local income taxes resulting from a nonrefundable contribution or advance by the customer in compliance with this rule will be recorded as a deferred tax and appropriately reflected in the Utility's rate base. These deferred taxes will be amortized over the remaining tax life of the asset.

EXHIBIT
JA-7
admitted

DIRECT TESTIMONY OF KEVIN LARSON
UNISOURCE ENERGY CORPORATION

DECEMBER 18, 2002

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Kevin P. Larson. My business address is One South Church Avenue, Tucson, Arizona 85701.

Q. What is your position with UniSource Energy Corporation ("UniSource" or "Company")?

A. I am Vice President, Chief Financial Officer and Treasurer of UniSource. I also hold the same positions with Tucson Electric Power Company ("TEP").

Q. Please summarize your professional experience and education.

A. I joined TEP in 1985 as a financial analyst, and in 1991, I became Assistant Treasurer. In 1994, I was elected Treasurer, and in 1997, I became a Vice President at TEP. I became Vice President, Chief Financial Officer and Treasurer of TEP and UniSource in October 2000. I report directly to Mr. James Pignatelli, the Company's President and Chief Executive Officer.

My educational background includes a Bachelor of Science degree in Economics from the University of Minnesota, Minneapolis, and graduate work in finance at the University of Arizona. I am also a Chartered Financial Analyst ("CFA").

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is twofold. First, I will provide additional information in support of the financing plan described in Section V of the Joint Application filed by UniSource and Citizens Communications Company ("Citizens") for the sale and transfer of certain electric and gas assets to UniSource ("Joint Application"). Second, I will provide a cost of capital estimate for use in the amended general rate case for Citizens' Arizona Gas Division ("Gas Rate Case").

II. SUMMARY OF FINDINGS AND CONCLUSIONS

Q. Please summarize your findings and conclusions with respect to the financing plan described in the Joint Application.

A. The financing plan contained in the Joint Application provides UniSource with the flexibility needed to fund the acquisition in a timely and cost efficient manner. Due to the potential for unanticipated changes in the capital markets, and the timeframe required for closing the purchase transaction, the flexibility requested in the Joint Application is both reasonable and necessary. The ability to fund the debt portion of the purchase price with either bridge financing or long-term bond financing may be critical if the corporate bond market is in turmoil. Similarly, the ability to fund a portion of the equity financing through a loan from TEP to UniSource, and to invest essentially all of the new UniSource stock offering proceeds directly in the New Utility Companies, may be critical if the equity markets are not receptive to a stock issuance by UniSource. The ability of the new operating companies to enter into a new revolving credit facility is also important from the standpoint of continued liquidity support. When viewed as a whole, the various components of the financing plan are designed to provide the new operating companies with a balanced and cost effective capital structure, as well as a reasonable degree of financial flexibility. Additionally, the transactions contemplated under the plan should have no adverse effect on TEP's financial standing or ability to raise capital. As a consequence, I believe the plan is consistent with the public interest, and recommend that the Commission approve the plan in its entirety.

Q. Please summarize your findings and conclusions with respect to the appropriate cost of capital for use in the amended Gas Rate Case.

A. The new corporate entity which will own and operate the acquired gas assets is expected to have an initial capital structure consisting of approximately 40 percent common equity capital and 60 percent long-term debt capital. Although the cost of equity capital will likely be higher than the 11.0% rate of return on equity requested by Citizens, UniSource is willing to accept this value for rate setting purposes. The cost of debt capital will depend on the credit ratings assigned to the new company and the interest rate environment at the time of issuance. A reasonable estimate of the cost of this new debt capital is 7.75%. Based on these component costs of capital, and a capital structure with 40% common equity, I recommend using a weighted average cost of capital of 9.05% for rate setting purposes.

III. FINANCING PLAN – JOINT APPLICATION

Q. Please summarize the financing plan contained in the Joint Application.

A. UniSource intends to form one or more wholly-owned public service corporations which will own and operate the assets purchased from Citizens ("New Utility Companies"). A substantial portion of the acquisition would be funded with debt securities issued by the New Utility Companies or by an intermediate holding company under UniSource. The balance of the acquisition funding needs, as well as the initial working capital needs of the New Utility Companies, would be provided by UniSource in the form of an equity investment in the New Utility Companies. As described in the Joint Application, a substantial portion of this equity investment may be funded through the issuance and sale of UniSource common stock. However, in order to preserve some flexibility in financing this equity investment, the Joint Application requests that TEP be authorized to lend money to UniSource for the purpose of funding up to $50 million of the acquisition price. Additionally, to the extent that UniSource funds the acquisition through the issuance of additional common stock, the Joint Application seeks a waiver of the existing requirement that at least 30% of the proceeds of any public stock issuance be invested in TEP.

Q. Please describe the corporate structure that UniSource intends to use for this transaction.

A. As described above, UniSource plans to form one or more wholly-owned subsidiaries that will own and operate the acquired assets. One scenario being considered is the formation of an intermediate holding company ("HoldCo") that will hold ownership in two separate operating companies, one containing the acquired electric properties ("ElecCo") and the other containing the acquired gas properties ("GasCo"). Under this scenario HoldCo would issue debt securities and receive equity funding from UniSource for the purpose of funding the property purchases and working capital needs of ElecCo and GasCo. Alternatively, UniSource may establish ElecCo and GasCo as direct subsidiaries of UniSource, or combine the electric and gas properties into a single wholly-owned operating company. Under these scenarios, each operating company would issue its own debt securities and receive equity funding directly from UniSource. A final decision regarding corporate structure will be made after careful analysis of the costs and benefits of each alternative.

Q. Please describe some of the costs and benefits associated with each alternative.

A. The primary benefit associated with forming an intermediate holding company is the potential reduction in financing costs associated with a larger bond issuance. Issuance size affects trading liquidity in secondary markets as well as the potential universe of investors on the issuance date. Generally, debt securities can be issued on better terms if there are more investors bidding on the bonds and there is an expectation of a liquid secondary market after issuance. Similar financing benefits can be achieved by forming a combined gas and electric operating company directly under UniSource. However, the potential benefits of maintaining separate operating companies for gas and electric assets would be lost. These benefits include an improved ability to focus management attention and future growth strategies on a particular energy sector.

Q. Why does the Company prefer to establish the New Utility Companies as wholly-owned subsidiaries under UniSource as opposed to TEP?

A. UniSource prefers to establish the New Utility Companies as sister companies to TEP for several reasons. First, this structure would better insulate TEP from the financial performance and creditworthiness of the New Utility Companies, and vice versa. Second, this alternative results in a more simplified capital structure from a holding company perspective, and avoids double leverage by the operating companies. Third, this structure would improve the visibility of the New Utility Companies within the UniSource investment portfolio. This enhanced visibility would help investors better understand and value the diversity of operations under the UniSource umbrella, and could potentially translate into improved access to equity capital by UniSource.

Q. What capital structure is UniSource targeting for the New Utility Companies?

A. If possible, UniSource would like to capitalize the New Utility Companies at a level consistent with an investment grade credit rating. The minimum investment grade ratings assigned by the major rating agencies are BBB- from Fitch, Baa3 from Moody's, and BBB- from Standard & Poor's. Standard & Poor's refers to debt securities with a BBB credit rating as having "an adequate capacity to pay interest and repay principal," whereas speculative grade debt (BB rated and below) is regarded as having "predominantly speculative characteristics with respect to capacity to pay interest and repay principal." In today's credit markets, the additional interest cost or "credit spread" between speculative grade issuers and investment grade issuers has widened considerably. As a consequence, significant interest savings can be achieved if the New Utility Companies receive investment grade ratings on their debt securities.

Q. What capital structure is consistent with an investment grade rating?

A. Since credit ratings depend on a variety of factors, financial and otherwise, a precise answer to this question is difficult. However, it is possible to define a potential range of debt and equity mixes that are consistent with investment grade ratings. For example, Standard & Poor's publishes financial ratio guidelines that may be used to assess the likelihood of receiving an investment grade rating. For transmission and distribution utilities, these ratio guidelines suggest that a debt to total capital ratio in the range of 53-64% is generally consistent with a BBB credit rating. A study recently published by Fitch supports a similar range of values. Based on actual financial data for the period ending June 30, 2002, the Fitch study identified a median ratio of debt to total capital of 53% for electric and gas distribution utilities with a BBB+ senior debt rating, and 59% for distribution utilities with a BBB or BBB- rating. However, since many factors are considered in the credit rating process, a fairly wide range of debt to capital ratios may be observed within any given ratings category. For example, the debt to total capital ratio for BBB rated companies in the Fitch study ranged from a low of 46% to a high of 77%. Based on information provided by the rating agencies, and my knowledge of the properties being acquired, I believe that an initial debt to total capital ratio of 50-70% may allow the New Utility Companies to achieve an investment grade credit rating.

Q. If the New Utility Companies are capitalized at a level consistent with an investment grade credit rating, is there any guarantee that the new debt securities will receive investment grade ratings?

A. No. As mentioned above, many factors are taken into account in assigning credit ratings, including the quality of management, the quality of regulation, and other financial measures such as profitability, cash flow, and interest coverage. Additionally, the specific terms of the securities being issued are also very important, such as the financial covenants of the issuer and any security interests granted to lenders. Finally, some rating agencies place significant emphasis on the credit profile of the consolidated group of companies in assigning individual credit ratings. Although UniSource does not have rated debt securities, TEP currently has senior secured debt ratings of Ba2 from Moody's, BB+ from Fitch, and BBB- from Standard & Poor's

Q. What types of debt securities will be issued by the New Utility Companies?

A. Our plan is to issue corporate bonds with final maturities of 30 years or less. These bonds may be issued in several different series, each having its own maturity date and interest rate, and may be issued as either secured or unsecured obligations. However, since corporate bond market conditions are subject to change, it may be necessary or desirable to use interim bridge financing instead. The use of bridge debt financing is fairly common for large acquisitions or capital projects since it provides flexibility in the timing of permanent bond and equity financing. This type of financing is typically provided through a credit agreement with commercial banks and other institutional lenders. UniSource is requesting authority to enter into such an agreement for a term of up to three years. Additionally, UniSource is seeking authority for the New Utility Companies to enter into a revolving credit facility for ongoing liquidity support. Due to the seasonal nature of the utility business, and our need to fund temporary under-collections of gas commodity costs under the Purchased Gas Adjustor mechanism, the New Utility Companies will need a source of funds to satisfy short-term liquidity needs. As such, the Joint Application seeks authority for the New Utility Companies to issue up to $50 million in notes or guarantees under a revolving credit facility.

Q. How would the formation of an intermediate holding company affect the structuring of debt securities for the New Utility Companies?

A. An intermediate holding company, if formed, would essentially serve as a conduit for acquiring new debt capital. As discussed earlier, such a structure would allow for larger sized debt issues and a resulting decrease in anticipated financing costs. In addition, the diversity of electric and gas assets may also enhance the credit rating of a combined financing. Structurally, the receipt of debt proceeds from HoldCo would be evidenced by the New Utility Companies through either a note payable to HoldCo, through a guarantee of HoldCo debt, or through the issuance of mortgage bonds held as collateral for HoldCo lenders. Under this last scenario, the bonds issued by the New Utility Companies would be secured with a mortgage lien on the electric and gas properties acquired from Citizens and other properties of the New Utility Companies. Regardless of which structural alternative is used, any HoldCo borrowings on behalf of the New Utility Companies would ultimately have to be repaid through the cash flows of the New Utility Companies.

Q. What financing terms are expected on the debt securities to be issued or guaranteed by the New Utility Companies?

A. The interest rates will be based on prevailing rates in the credit markets and will be greatly impacted by the perceived creditworthiness of the New Utility Companies. The interest rate premium (or credit spread) over comparable U.S. Treasury bonds or bills will be much lower if the debt securities are deemed to be investment grade as opposed to speculative grade. Other terms and conditions for the debt securities and related credit agreements are expected to be similar to those obtained by other gas and electric utilities.

Q. The Joint Application seeks authority to issue debt in an aggregate amount not to exceed $175 million, or approximately 70% of the aggregate purchase price and initial working capital requirement. Why is the request stated in terms of an amount "not to exceed"?

A. The request is stated in this manner in order to provide UniSource with necessary financing flexibility. The relative costs of debt and equity capital are constantly changing, as are market expectations regarding credit quality and the financial measures needed to maintain credit quality. Under these circumstances, flexibility in executing the Company's financing plan is necessary to achieve a balanced and cost effective capital structure.

Q. Why does the Joint Application seek approval of a loan from TEP to UniSource?

A. This request is being made to achieve flexibility in financing the Company's equity investment in the New Utility Companies. The equity markets have been extremely volatile over the past several years, and especially so for energy concerns. The issuance of new common stock by UniSource may simply not be feasible or appropriate at the time of the acquisition. Therefore, in order to ensure that acquisition funding is available, the Joint Application seeks authority for TEP to lend up to $50 million to UniSource.

Q. What conditions might preclude UniSource from issuing additional shares of common stock?

A. Before any new shares can be issued, the impact on existing shareholders must be considered. UniSource has a fiduciary responsibility to its shareholders to preserve and increase the value of their investment in the Company over time. If the end result of a new share issuance and investment of proceeds is a reduction in per-share earnings and market value, then the issuance and related acquisition would be contrary to shareholder interests. Such a situation could arise if the Company's stock price is temporarily depressed at the time of issuance, thereby increasing the number of shares needed to raise a certain level of proceeds. Similarly, if the return on invested proceeds does not generate sufficient growth in consolidated earnings, per-share earnings and market value would fall, again leading to a reduction in shareholder value. Either scenario would be detrimental to shareholders, thereby precluding a large issuance of shares by UniSource.

Q. If a loan from TEP to UniSource is deemed necessary, how would such a loan affect TEP?

A. Based on current forecasts of TEP cash flow and liquidity, a loan of $50 million would not affect TEP's stated objective of continuing to improve its equity ratio, including using $30 million - $50 million per year for early debt retirements and lease debt purchases. TEP would therefore remain on course to gradually de-leverage its balance sheet and improve its credit ratings. Additionally, TEP would be able to earn a higher rate of return on the loan amount than is currently available from short-term money market investments. In summary, such a loan would not impair TEP's financial status or its ability to raise additional capital on reasonable terms.

Q. If UniSource issues additional common stock to fund the acquisition, would UniSource be required to invest a portion of the issuance proceeds in TEP?

A. Pursuant to TEP's Holding Company Order in Commission Decision No. 60480, as amended by the Settlement Agreement adopted in Decision No. 62103, UniSource is required to invest at least 30% of the proceeds of a public common stock issuance in TEP. However, as described in the Joint Application, UniSource and TEP are requesting a waiver of this requirement for purposes of funding the acquisition of Citizens' gas and electric properties. In light of the potential risks associated with a new share issuance, such a waiver is both reasonable and necessary. Should this waiver be granted, UniSource would invest essentially all of the equity proceeds directly into the New Utility Companies.

Q. What would be the terms of the loan from TEP to UniSource?

A. Any such loan would be evidenced by a promissory note payable to TEP. The note would have a final maturity of up to ten years, with interest on the note due and payable annually. The rate of interest would be tied to the cost of borrowing under TEP's current revolving credit facility or any subsequent credit facility. This rate is currently equal to LIBOR plus four percent. Although TEP does not anticipate borrowing on this facility to fund the loan to UniSource, it does represent the opportunity cost to TEP should it need to borrow funds.

Q. Do you have any more observations regarding the financing plan described in the Joint Application?

A. Yes. As a final observation, I would note that the proposed acquisition and related financing represent a fairly large transaction for a company the size of UniSource. Although the Company certainly has the means to complete the transaction, it must be carefully planned and executed in order to reap the benefits intended for customers and shareholders. In light of the risks attendant with such a transaction, UniSource is seeking a fair amount of flexibility in terms of the corporate structure and financing to be employed. In my view, a high degree of flexibility is both reasonable and necessary, and will serve to benefit all stakeholders in the long-run. In the interim, I intend to keep the Commission Staff and other interested parties apprised of our progress and to provide additional details as they become available.

IV. COST OF CAPITAL – GAS RATE CASE

Q. What adjustments are you proposing to the rate of return requested by Citizens in its Gas Rate Case?

A. I recommend making two adjustments to the weighted average cost of capital and requested rate of return. First, I recommend using a capital structure that better reflects the financing plan described in the Joint Application. Second, I recommend using a cost of debt that reflects the anticipated cost of debt to the New Utility Companies.

Q. What capital structure are you recommending for the Gas Rate Case?

A. UniSource anticipates capitalizing the New Utility Companies with a common equity investment in the range of 30-50% of total capital. As such, I recommend using the midpoint of this range for rate setting purposes. For purposes of calculating the weighted average cost of capital, the capital structure would therefore consist of 40% common equity and 60% long-term debt.

Q. What cost of debt are you recommending for the Gas Rate Case?

A. As stated above in Section III of my testimony, the Company's preferred alternative is to issue corporate bonds either through an intermediate holding company or directly by the New Utility Companies. These bonds may be issued in several different series, each having its own maturity date and interest rate. Assuming the bonds are issued with low investment grade credit ratings (Baa or BBB), and that bond market conditions do not change materially between now and the issuance date, a cost of debt in the range of 7% to 8% should be attainable by the New Utility Companies. This estimate falls within the range of debt costs realized by other BBB rated utilities during the second half of 2002. BBB rated utility bonds with maturities of seven to ten years have been issued over this time period at an annual cost (or yield to maturity) of between 5.6% and 8.1%. Comparably rated bonds with longer maturities (15 to 30 years) have also been issued at an annual cost of between 6.8% and 7.6%. Although the estimated cost of debt for the New Utility Companies is at the high end of each range, this is reasonable to expect in light of the relatively small size of the New Utility Company issuances, as well as the limited track record for these new companies. Additionally, as discussed previously in my testimony, there is no guarantee that the bonds will actually achieve an investment grade credit rating. Speculative grade issuers have had a very difficult time issuing new bonds in recent months, and when successful, these issuers have had to pay a significantly higher price for the capital relative to investment grade issuers. Based on what is known today, my best estimate for the cost of debt to be issued by the New Utility Companies is 7.5%. After factoring in the amortization of debt issuance costs, as well as the costs of arranging and maintaining a revolving credit facility, I recommend using a cost of debt of 7.75% for rate setting purposes.

Q. You previously mentioned that the cost of equity capital to the New Utility Companies will likely be higher than the 11% return on equity requested by Citizens. What is the basis for your statement?

A. Citizens requested return on equity is based on the low end of a range estimated by witness Robert G. Rosenberg. This range was based on the cost of equity capital for a comparable group of gas distribution companies. Most of the companies in this group have credit ratings higher than Baa/BBB. Additionally, the group has a median equity to capital ratio of 50%. Since the New Utility Companies are expected to have lower credit ratings and slightly higher debt leverage relative to Mr. Rosenberg's comparable group, the cost of equity capital for the New Utility Companies will likely be higher than the 11% requested by Citizens. However, for purposes of setting rates in this proceeding, UniSource is willing to accept the 11% return on equity requested by Citizens.

Q. Based on the mix of capital and component costs of capital you have recommended, what is the overall weighted-average cost of capital you are recommending?

A. The overall cost of capital I recommend using in the Gas Rate Case is 9.05%, as summarized in the following table:

	% of Total Capital	Cost Rate	Weighted Cost
Debt	60.0%	7.75%	4.65%
Common Equity	40.0%	11.00%	4.40%
Total	100.0%		9.05%

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT
JA-8
admitted

SUPPLEMENTAL TESTIMONY OF KEVIN LARSON

Q: What is the purpose of your supplemental testimony?

A. The purpose of my testimony is to address the questions raised by Commissioner Gleason in his letter to the parties dated April 24, 2003. The questions raised by Commissioner Gleason are repeated below in the same order as they appeared in his letter.

Q. What are the policy implications of a regulated utility loaning money to its parent company in exchange for an interest in a third company where the value of the security is questionable?

A. From a policy perspective, the Commission established AAC R14-2-801 et seq., Public Utility Holding Companies and Affiliated Interest, as a regulation to monitor, control and review transactions between affiliated companies. Certain affiliate transactions, including loans, must be reviewed and approved by the Commission. The Commission reviews the transaction to determine if the transaction would impair the financial status of the public utility, otherwise prevent it from attracting capital at fair and reasonable terms, or impair the ability of the public utility to provide safe, reasonable and adequate service.

In the case of TEP, which is seeking authority to lend up to $50 million to its parent company to help fund the acquisition of utility properties from Citizens, I believe that a $50 million loan from TEP would not impair TEP's financial status, its ability to attract capital, or its ability to meet its public service obligation. Under the current rate freeze, TEP is anticipated to generate enough cash flow to fund a $50 million loan, meet its ongoing capital expenditure requirements and retire an average of $30 million to $50 million of debt and lease obligations each year. Due, in part, to TEP's strong cash flows, we expect the credit rating agencies to sustain the current credit rating of TEP even if a $50 million loan is provided. Further, to the extent that TEP's cost of capital were to increase as a result of the loan to UniSource, the Settlement has specific "hold harmless" language in it that would prevent TEP from passing along such a cost increase to its customers.

Q. How do customers benefit from a TEP loan to UniSource? What risks are involved?

A. As specified in the Settlement, a portion of the interest received by TEP on the loan will be recorded as a deferred credit and used to reduce the future rates charged to TEP retail customers. Additionally, TEP will earn a higher rate of return on the loan amount relative to current money market rates. This incremental interest income will serve to increase TEP's earnings and common equity balance. The financial flexibility that such a loan would provide UniSource in funding the acquisition should also be considered. To the extent that economies of scale are ultimately realized by UniSource and TEP as a result of the acquisition, flexibility in financing the acquisition should be viewed as a means of obtaining long-term cost savings for TEP and its customers.

Risks associated with such a loan would be minimal because the cash resources of UniSource are expected to be more than sufficient to pay the estimated annual interest payments of only $3.25 million per year on a $50 million loan balance. By the end of the four-year loan term, UniSource would repay the loan by using cash on hand or by raising new funds in the debt or equity markets. In light of the financial progress made by TEP, the largest subsidiary of UniSource, and the solid financial footing being planned for the new UniSource subsidiaries ("New Companies") that will own and operate the Citizens assets, the prospects for loan repayment are very high. In the unlikely event that UniSource would be unable to meet the loan repayment obligation, ownership of the New Companies would transfer from UniSource to TEP per the terms of the Settlement Agreement. Since the total equity investment by UniSource in the New Companies is expected to be approximately $90 million, the value of these ownership interests should be well in excess of the loan amount from TEP.

Q. How will TEP's $50 million loan to UniSource affect TEP's liquidity? Will TEP have to borrow the money in order to lend it to UniSource? If so, is the loan inconsistent with the policy found in FERC's February 21, 2003 Order in Docket No. ES02-51-00 relating to the issuance of debt by a regulated utility for non-utility purposes? If TEP does not have to borrow money to loan $50 million to UniSource, how will the reduction of TEP's cash-on-hand affect its financial health?

A. As described above, TEP's net cash flow is expected to be sufficient to meet planned capital spending needs and our stated objectives for debt and lease retirements. Additionally, TEP has a $60 million revolving credit facility to help it meet short-term liquidity needs. Since TEP's cash flows are highly seasonal, the ability to fund a $50 million loan to UniSource with cash on hand is dependent on when the acquisition is closed. Current projections of TEP cash flows for 2003 reflect an anticipated cash balance of $42 million by the end of July, growing to over $100 million by the end of October. If the acquisition occurs in July or early August, TEP may have to borrow from its revolving credit facility to fund a portion of any loan to UniSource. However, any such borrowing under TEP's revolving credit facility would be repaid in full within a short period of time.

Regarding the above referenced FERC order, there are many differences between that case and the circumstances in this proceeding. The most significant difference is that TEP would not be issuing new long-term debt to fund any loan to UniSource. Additionally, any loan proceeds would be used by UniSource to acquire *regulated* assets within the same state regulatory jurisdiction, and would not be used to fund *unregulated* parent company investments. For these reasons, as well as others, the authority sought by TEP in this proceeding is not in conflict with the principles established by the FERC.

Q. Could TEP guarantee a $50 million loan by UniSource? What benefits does a guarantee provide?

A. If the Commission granted authority for a TEP guarantee, UniSource could attempt to obtain outside financing on the basis of the guarantee. However, such a transaction would involve additional time and expense to UniSource, and would add to the overall debt leverage of the consolidated entity. The guarantee would also be taken into account by credit rating agencies and potential lenders in assessing the creditworthiness of TEP.

Q. Since the purchase price is $230 million and the Settlement allows the New Companies to borrow up to $475 million and UniSource is providing $75 million to $125 million in equity, why couldn't UniSource acquire Citizens Gas and Electric Divisions without TEP's financial assistance?

A. The levels of debt that the New Companies will be allowed to borrow to fund the acquisition, shown on Appendix A to the Settlement are not additive. The funding alternatives requested in Appendix A are to provide UniSource with flexibility and assurance that we can fund the transaction on the acquisition date. For example, the bridge financing provides us an alternative if a more permanent form of capital is unavailable, too expensive, or inappropriate at closing. In total, assuming a purchase price of $230 million, we expect to fund approximately $140 million of the acquisition with longer term debt at the operating company level and approximately $90 million with an equity investment from UniSource. Additionally, up to a $50 million revolving credit facility is intended to support the short-term liquidity needs of the New Companies and is not intended to fund the initial purchase price.

The source of the approximate $90 million equity investment could come from cash on hand at UniSource, from cash borrowed from TEP, or from an external financing at UniSource. Although UniSource currently has a shelf registration pending with the SEC that would allow UniSource to issue up to four million shares of common stock, there is no guarantee that stock market conditions will be conducive to such an offering. As such, the ability of UniSource to borrow money from TEP provides additional flexibility in funding the acquisition in a timely and cost effective manner.

Q. Does the current restriction on dividend receipts sufficiently encourage a parent company to increase the equity ratio of its subsidiaries? Specifically, since TEP is below 37.5% equity, what incentive is there to increase its ratio unless that effort brings it above the

37.5% benchmark? Alternatively, since UniSource receives dividends on 75% of the earnings if TEP's equity ratio is 35%, 25% or even 15%, what incentive does UniSource have to prevent TEP's equity ratio from falling?

A. The cost and availability of debt capital is a function of perceived creditworthiness. Since a company's net worth is typically used as an important measure of creditworthiness, TEP's equity ratio has a significant effect on its credit ratings and cost of debt capital. As a subsidiary of a publicly traded company, the management of TEP has a fiduciary duty to shareholders to reduce costs and improve profitability. This fiduciary duty acts as a strong incentive to increase TEP's equity ratio and reduce its cost of borrowing over time. Additionally, TEP is required to abide by certain financial covenants contained in its loan agreements. Compliance with these covenants would not permit TEP to lower its equity ratio through large new borrowings or through dividend payments in excess of annual earnings.

Q. Has TEP made progress on improving its balance sheet and equity ratio?

A. Yes, TEP has made significant improvement. As shown on the attached Exhibit 1, from December 1998 to December 2002, TEP's equity improved from $230 million to $337 million and its equity ratio increased from 16% to 23%.

Q. Should the Commission consider implementing a graduated dividend structure to encourage a parent to increase the subsidiary's equity ratio? For example, if a subsidiary's equity ratio fell below 25%, the parent company would receive dividends from 60% of the earnings. If the ratio fell below 15%, the parent would receive dividends from 30% of the earnings. Would such a graduated structure provide an incentive to maintain as high an equity ratio as possible?

A. As with other corporations, decisions regarding dividend policy appropriately fall within the purview of the regulated company's Board of Directors. The restrictions on TEP dividends contained in prior Commission orders, as well as the proposed Settlement, were the result of voluntary negotiations between TEP's management and other parties to Commission proceedings. As stated previously, UniSource has a natural incentive to preserve its financial well-being and to reduce its cost of capital through its fiduciary duty to shareholders to reduce cost and improve profitability. UniSource believes it would be inappropriate to require additional external "incentives" on dividend policy.

Q. Generally, does a higher equity ratio produce a financially healthier utility which, in turn, allows it to have increased operating funds, incur loans at a lower interest rate and to be better prepared for any unexpected occurrences in the market thus protecting the rate payers?

A. Generally speaking, yes. However, it should be noted that equity capital is the most expensive source of capital. For that reason, most corporations attempt to finance themselves with a reasonable mix of debt and equity capital. Given the cost advantage of debt capital, the impact on a utility's cost of service should be considered in any evaluation of capital structure.

A. Does this conclude your supplemental testimony?

A. Yes.

1

Tucson Electric Power

	12/31/1998	12/31/1999	12/31/2000	12/31/2001	12/31/2002
Equity	230	270	296	322	337
Debt	1,186	1,185	1,134	1,132	1,130
Total	1,416	1,455	1,430	1,454	1,467
Equity	16%	19%	21%	22%	23%
Debt	84%	81%	79%	78%	77%
Total	100%	100%	100%	100%	100%

EXHIBIT
JA-9
Admitted

TESTIMONY OF MICHAEL J. DECONCINI, JR.

UNISOURCE ENERGY CORPORATION

APRIL 28, 2003

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Michael J. DeConcini, Jr. My business address is One South Church, Tucson, Arizona, 85701.

Q. With whom are you employed?

A. I am Senior Vice President of Investments and Planning for UniSource Energy and Senior Vice President and Chief Operating Officer of Energy Resources for Tucson Electric Power Company ("TEP").

Q. What are your duties and responsibilities at TEP?

A. My areas of responsibility include fuels procurement and management, wholesale power trading and marketing, and power plant operations at TEP. I am also involved in UniSource affiliate investments and strategic direction related to planning and growth opportunities, including acquisitions such as the Citizens Arizona properties, the subject of this case. I have been with TEP/UniSource for 14 years and involved in the wholesale power areas in various positions for 11 of those years.

Q. What is your educational background?

A. I have a Bachelor of Science Degree in Finance from Moorhead State University and a Master of Business Administration Degree from Arizona State University.

Q. What is the purpose of your testimony?

A. My comments will address comments submitted by the City of Nogales regarding the efficacy of the contract between Citizens and Pinnacle West Capital Corporation effective June 1, 2001 and dated July 16, 2001 ("PWCC Contract"), as well as augment certain issues discussed in the Staff Report regarding the PWCC Contract.

Q. Please summarize your testimony.

A. In short, my testimony demonstrates that the PWCC Contract was prudent at the time it was entered into and provides a fixed price comparable to other alternatives to Citizens but with less operating and financial risk.

II. PRUDENCE OF PWCC CONTRACT

Q. Please describe the highlights of the PWCC Contract.

A. It is a full-requirements, firm power contract at a fixed price of $58.79/MWh for the term and includes transmission to Citizens receipt points on the WAPA transmission system. Citizens peak load in 2002 was approximately 320 MW with a load factor of 50% and annual growth rate of approximately 3%. The contract does not create stranded costs in a competitive environment as competitive power procured by customers is excluded from the supply agreement.

Q. Define the term "full requirements".

A. Full requirements means that the supplier will provide any and all power consumed by the purchasing entity on an instantaneous basis including future load growth. It provides instant access to the necessary capacity, energy and ancillary services required by the purchasing entity's retail customers and assumes all the operational and financial risks associated with meeting that demand.

Q. Please describe the components in the PWCC Contract that make up the full requirements?

A. *Firm Capacity and Energy* – PWCC must maintain sufficient available capacity to provide Citizens' requirements at all times, including during weather extremes. PWCC must further insure sufficient capacity is added to provide for Citizens' load growth.

Network Transmission charges – The PWCC Contract price includes the necessary network transmission service necessary to deliver power to Citizens' receipt points on WAPA's transmission system (Pinnacle Peak and Saguaro substations).

Transmission losses – Transmission losses on PWCC's system to Citizens' receipt points are also included in the fixed price.

Ancillary services – These services include such items as energy imbalance and regulation that are required to provide uninterrupted and instantaneous response to Citizens' changing demand.

Q. Given that the PWCC Contract contains all of these components, how do you value the contract?

A. To fully evaluate the current value of the PWCC Contract, one must first identify all of the components included in the PWCC Contract and then ensure that the market prices and alternatives include these components. As previously stated, the PWCC Contract includes firm capacity and energy, transmission, losses to Citizens' receipt points, and ancillary services necessary for load-following all of which have value/costs which must be determined.

Q. How do you determine such costs?

A. Firm energy and capacity are easy to determine for 100% load factor products by using forward price curve data that is readily available. However, taking into account the necessary components to provide load-following ability complicates matters. The only component of the price that is fairly easy to value is network transmission. The remaining value is best estimated by pricing a load-following resource-based alternative.

Q. What is the approximate value of the network transmission service embedded in the PWCC Contract?

A. It is approximately $3.35/MWh based on 2002 data from Pinnacle West's OATT Network Service Agreement with APS for serving Citizens.

Q. What were the forward prices for contracts similar to the PWCC Contract entered into during the period that PWCC and Citizens were negotiating?

A. There were numerous contracts entered into during this period, the majority of which were in California. California Energy Resource Scheduling, the California state entity which entered into long-term energy contracts on behalf of the load-serving utilities in 2001, has a list of its contracts posted on its website (http://wwwcers.water.ca.gov/contracts.html). Because California and Arizona had such directly connected markets during this period, these contracts provide a good indication of prices in Arizona and the rest of the Southwest. The table below shows a sample of such fixed price contracts that were entered into during the same 2001 period that Citizens and PWCC negotiated their agreement. (See the website referred to above for complete contract details).

Effective Date	Term	Product(s)	Current Price*
Mar 23, 2001	Mar 2001-Dec 2011	7x24	$61.00
Mar 2, 2001	Mar 2001-Dec 2004	On-Peak, 7x24	$119.50
Feb 9, 2001	Feb 2001-Dec 2005	On-Peak	$115/$127
May 24, 2001	May 2001-Jun 2012	On-Peak	$169

*Price per Megawatt-hour for current energy delivery as of April, 2003

From the Table above and with more detailed analysis of the contracts on the website, one can clearly see that the energy prices for long-term agreements entered into during the first half of 2001 were significantly higher than the price PWCC and Citizens agreed to in the Contract. It is also important to note that: 1) none of the above California contracts is a full-requirements contract like the PWCC Contract, as they are 100% capacity take or pay fixed delivery contracts, and 2) none of the above referenced contracts has been renegotiated.

Q. If you were to price a load-following resource-based alternative based on the forward market prices in April of 2001, what price range would you have thought appropriate?

A. UniSource looked at analyzing the price for a contract similar to the PWCC Contract in two ways. First, utilizing a resource-based alternative, and second, using a market-only alternative. The price range for these two options was approximately $60 to $80/MWh.

Q. Please describe the resource-based analysis.

A. TEP analyzed what a fully dispatchable combined cycle would cost Citizens to serve its load assuming immediate availability and full access to economic market purchases and sales using forward gas prices based on the same mid-May 2001 TEP forecast and standard plant operating assumptions. This analysis resulted in wholesale delivered price, including the network transmission costs to Citizens' receipt points, of approximately $60/MWh. The analysis was performed using TEP's ProMod production modeling program and the assumptions delineated in Exhibit 1.

Q. Why is the resource-based price so much lower than the contracts entered into in California?

A. The resource-based analysis included the assumption that the capacity (plant) would be immediately available which would not have been feasible at the time. Due to the necessary time to permit and build a new plant, the California contracts reflected market-based prices for the first 2 years which put upward pressure on the term contract prices.

Q. Please describe your market-based analysis.

A. Using forward prices as of mid-May 2001 from TEP's own historical forecast and Citizens hourly load shape and assuming that all of Citizens power would be procured from the market, the average price for firm energy and the network transmission costs to Citizens' receipt points would be approximately $80/MWh.

Q. How do these two options compare to the PWCC Contract with all of its components?

A. These alternatives place much more risk on Citizens and its retail customers as they require Citizens to manage the deliverability and availability of fuel and/or market power purchases, market price risk of gas and/or power, operational risks of resources and the risk of stranded costs associated with competitive direct access. Further, neither of these two options contain the costs associated with load-following ancillary services.

Q. What are the costs for load-following ancillary services?

A. These costs vary from a number of factors, including the control area in which the load is served, the amount of load variability, the amount of reserves that are self-provided and resource performance characteristics. Due to this variability, we ignored these costs in the analysis, but would estimate the costs to be a few to several dollars per MWh.

Q. Are these prices consistent with what TEP saw during this period?

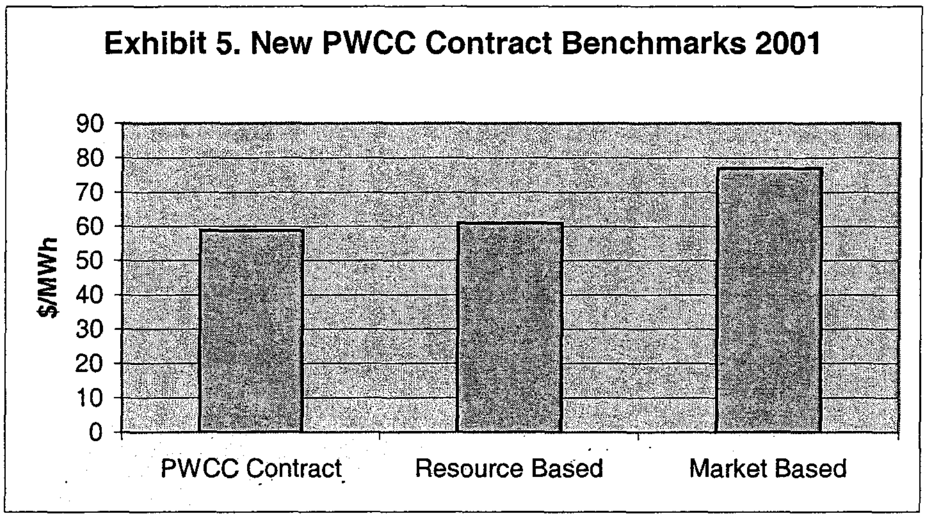
A. Yes. TEP was in the process of negotiating a 5 year sale at the time and had thoroughly evaluated the forward price curves.

Q. Did TEP feel that the forward price curve was an accurate reflection of expected future short-term prices?

A. Yes. TEP had no reason to believe otherwise. In fact, TEP purchased power gas and power for the summer of 2001 based on these forward curves.

Q. Do you feel that the PWCC Contract was a prudent purchase at the time?

A. In light of the information available to Citizens at the time of their negotiations with PWCC and TEP's own analysis and valuation of the market costs to supply Citizens' load on similar terms as the PWCC Contract, as well as the benchmarks provided by other wholesale agreements entered into during this period, I feel that the PWCC Contract was not only prudent but at a discount to other alternatives as demonstrated in Exhibit 5 below.



III. CURRENT VALUATION OF THE PWCC CONTRACT

Q. Are the current forward prices as quoted at the Palo Verde Hub a good benchmark for what Citizens should be paying for its power?

A. No. The current forward prices at Palo Verde represent a 100% capacity factor, take or pay energy price that has very little resemblance to the full-requirements, load-following, approximately 50% capacity factor nature of Citizens' load. In addition to these items, the demand of Citizens' retail customers is heavily weighted to hot summer months which generally produce the highest market power prices in the Southwestern U.S., including Arizona.

Q. What do you consider Citizens' likely alternative to the PWCC Contract for serving its load?

A. TEP has analyzed a resource-based alternative we believe would be the most likely and comparative alternative to a full-requirements contract like the PWCC Contract. The most obvious choice for a resource-based generation alternative to serve Citizens' load is a new

Combined-Cycle unit with sufficient capacity to cover Citizens' load. These new units have a heat rate in the range of 7,000 Btu/kW at 100% load and a capital installation cost in the range of $600 to $700/kW. TEP has estimated the current forward gas prices for the remainder of the PWCC Contract term at approximately $4.30/mmBtu for delivery at the Permian Basin. The delivered gas price includes transportation, fuel (losses), usage charges and taxes. Also included are transmission charges and losses.

Exhibit 2 details the all-in costs of gas and the expected all-in cost of providing a 50% capacity factor load like Citizens from a combined cycle plant. This all-in cost based on these assumptions alone amounts to $66/MWh. When the resource is utilized as part of a system that optimizes generation dispatch through market sales and purchases, it brings the total cost down to roughly $54/MWh. Both of these prices include network transmission to Citizens' receipt points. This was modeled using TEP's ProMod program in late March using assumptions listed in Exhibit 3.

Q. How does this option compare to the PWCC Contract?

A. A resource alternative has much more risk associated with it including deliverability and availability of fuel and/or market power purchases, market price risk of gas and/or power, operational risks of resources and the risk of stranded costs associated with competitive direct access. Further, the price does not contain the costs associated with all of the ancillary services necessary to compare directly to the PWCC Contract as previously discussed.

Q. Do you have any other data that validates your previous analysis of Citizens' contract alternatives?

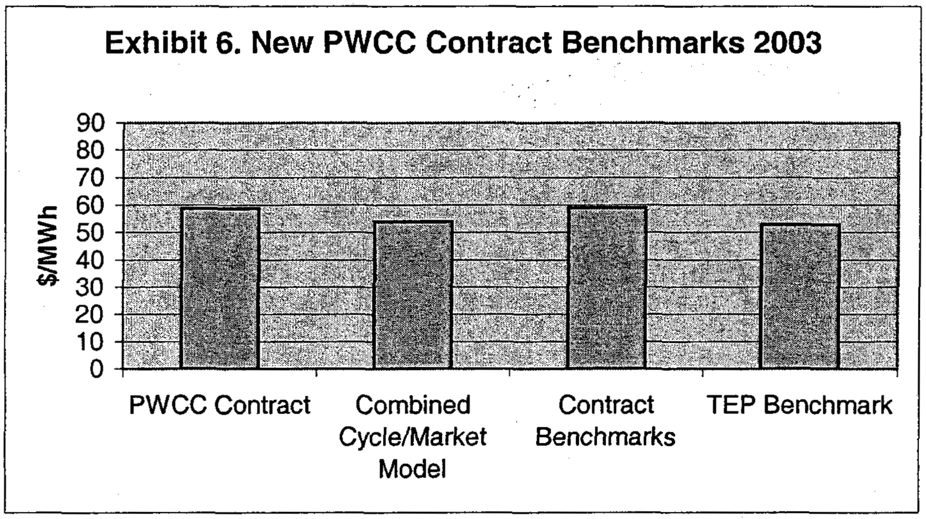
A. While it is difficult to get detailed information on third-party contracts, Exhibit 4 provides information on one such contract gleaned from data in an energy industry publication article.[1] While the contract is not a full-requirements contract, it does provide a relevant data point for evaluating forward prices for a somewhat shaped energy product. The price of this contract for 100 MW on peak and 50 MW off peak is $59/MWh.

TEP has also obtained current, competitive benchmarks that validate this analysis. TEP's Track B Competitive Solicitation bids received for supplying a portion of TEP's load provide the most current and directly comparable data available. While the specific details of most of these bids are confidential, the analysis shows that TEP's assumptions used in evaluating Citizens' options are indeed accurate. In fact, one such bid received without a confidentiality agreement in this solicitation was for a dispatchable Combined-Cycle plant for a term very close to that remaining on the PWCC Contract for delivery at Palo Verde with a $8.50 per kW per month capacity charge, an energy charge based on Daily San Juan gas price and a 8,000 btu/kWh heat rate, O&M charges of $3/MWh and additional startup charges which all closely align to TEP's assumptions in Exhibit 3. The Commission Staff and its independent monitor can confirm the congruence between TEP's assumptions and the other bids received as they have access to this confidential information.

Q. What is your view of the price of the PWCC Contract given this information?

[1] California Energy Markets, January 31, 2003, page 13.

A. As shown below in Exhibit 6, the PWCC Contract price is reasonable when compared to all the benchmarks reviewed by TEP. Further, the PWCC Contract leaves the majority of the operating and financial risks of the Citizens' supply with PWCC and provides more flexibility than any of these benchmarks.



IV. MISCELLANEOUS ISSUES/REBUTTALS

Q. How does the fact that the Settlement Agreement calls for UniSource to forfeit recovery of the PPFAC balance from customers, including the first 26 months of the PWCC Contract, affect the wholesale rate customers pay?

A. This Settlement Agreement and the forfeiture of customer recovery of the entire PPFAC balance, including the old PWCC agreement provides Citizens' customers with a wholesale energy rate equal to the current base rate of $0.04802 /kWh for the entire 2000/2001 period when prices in the wholesale market reached historically high levels of several times this rate. Due to the forfeiture of the first 26 months' (June 2001 through

July 2003) recovery of the PPFAC balance from the PWCC Contract, the effective rate seen by customers for that period was also the old base rate of $0.04802/kWh.

Q. The City of Nogales states in its opposition to the Settlement Agreement: "The allowance of 10% line losses in the wholesale power rate is unjustified as this level of line loss is for a distribution system, not a high voltage transmission system." Do you agree?

A. No, I believe the City of Nogales misunderstands the 10% line losses in the Settlement Agreement. The losses in the agreement include both the high voltage transmission losses on WAPA's transmission system (~4%) to get the power from the PWCC delivery points of Saguaro and Pinnacle Peak to substations to the high voltage side of Citizens' distribution system, ***plus*** the distribution losses (~6%). The sum of the transmission and distribution losses is approximately 10%. This number is also comparable to TEP's transmission and distribution combined losses of approximately 9.4%.

Q. It has been stated in others' testimony and/or comments during settlement proceedings that the PWCC Contract entered into by Citizens was during a period of "market manipulation." Is this relevant to this proceeding?

A. No. While FERC has stated in its March 26, 2003 Order in the California Refund case that there was apparent market manipulation during the time period that Citizens and PWCC entered into the agreement, FERC has not to date ruled that any contract entered into during this period should be abrogated. Further, both parties entered into the PWCC Contract with equal access to market prices, conditions and information and the contract is at the low end of prices for contracts signed during that timeframe. The existence or non-existence of market manipulation in 2000/2001 is irrelevant as I have demonstrated in my testimony and the PWCC Contract is a fair value on a going-forward basis.

Q. Does this conclude your testimony?

A. Yes, it does.

1

Exhibit 1.

Assumptions for Evaluation of New WPCC Contract Based on 2001 Data

LOAD-FOLLOWING RESOURCE EVALUATION

- Immediate availability
- TEP's actual forward gas price curve data used in its forecasting and planning in mid-May 2001 for the 7 year period of the PWCC Contract. Details are confidential.
- TEP's actual hourly forward spot price curve data used in its forecasting and planning in mid-May 2001 for the 7 year period of the PWCC Contract. Details are confidential.
- Citizens hourly load forecast.
- $8 per kW per month demand charge
- $3.35/MWh for Network Transmission based on 2002 actual data.
- Excluded other ancillary service charges related to load following, regulation, etc.
- Economically dispatched plant to spot market allowing purchases when under incremental cost of plant and sales of excess plant capacity to market when above incremental cost.
- Result was approximately $60/MWh

2

Exhibit 2.

Combined Cycle Generator Costs and Assumptions

Combined Cycle Generator

Initial Capital Cost	$650	per kW installed
Installed Cost for 300 MW	$195,000,000	
Resulting Capacity or Demand Charge	$7.75	per kW per month, based on 60/40% debt/equity ratio, 7.75% debt & 11% ROE
Combined Cycle Heat Rate	8,000	Btu/kWh based on 50% Capacity Factor
Total Cost of Gas (see below)	$4.99	per MMBtu
Production Energy Charge	$39.90	per MWh (heat rate times cost of gas)
Variable O&M Cost	$2.00	per MWh
Transmission Charges	$3.35	Based on 2002 Actual Data
Total Energy Charge	$45.25	per MWh
Citizens Peak Demand	300	MW, approximately
Avg Citizens Monthly Energy Required	109,500	MWh at a 50% load factor
Cost of Demand per month	$2,325,000	Monthly Demand times Demand Charge
Cost of Energy per month	$4,954,509	Mothly Energy times Energy Charge
Total Cost per month	$7,279,509	
Total Cost per month per MWh	**$66.48**	

Gas Cost		
Permian Basin Price - 5/03 - 6/08	$4.27	Based on Forward prices as of April 4, 2003
Fuel (losses)	$0.14	Fuel Losses on El Paso Pipeline
Taxes @ 5.6%	$0.25	State Tax Rate
Usage	$0.03	Basin Usage Charge for Permian
Transportation	$0.30	El Paso Transportation Cost
Total Gas Costs	**$4.99**	

3

Exhibit 3.

Resource-Based Alternative to New APS Contract

Assumptions:

- TEP's actual forward gas price curve data used in its forecasting and planning in early April 2003 for the remaining period of the PWCC Contract. Details are confidential.
- TEP's actual hourly forward spot price curve data used in its forecasting and planning in early April 2003 for the remaining period of the PWCC Contract. Details are confidential.
- Citizens Hourly load forecast.
- $8 per kW per month demand charge and a 350 MW Combined Cycle with a minimum load of 100 MW.
- Immediate availability
- $3.35/MWh for Network Transmission based on 2002 actual data.
- Excluded other ancillary service charges related to load following, regulation, etc.
- Economically dispatched plant to spot market allowing purchases when under incremental cost of plant and sales of excess plant capacity to market when above incremental cost.
- Result was approximately $54/MWh.

4

Exhibit 4.
2003 Contract Comparison

Nevada Power Contract

Supplier Calpine Power	Entered January-03
	3 year term 100 MW on-pk, 50 MW off-pk
Cost/yr (millions)	$43
MW	100
MWhs	730,000
$/MWh	$59

1394236.1

EXHIBIT
JA-10

DIRECT TESTIMONY OF DANIEL J. MCCARTHY
CITIZENS COMMUNICATIONS COMPANY

DECEMBER 18, 2002

Q. Please state your name and business address.

A. My name is Daniel J. McCarthy. My business address is 4400 NE 77th Avenue, Vancouver, Washington 98662.

Q. By whom and in what capacity are you employed?

A. I am employed by Citizens Communications Company ("Citizens"). Currently, I am holding two positions: President of Citizens' Public Services Sector, and President of Electric Lightwave, Inc. ("ELI"), a subsidiary of Citizens.

Q. What are your duties and responsibilities in your current position as President of the Public Services Sector?

A. As President of the Public Services Sector, it is my responsibility to oversee all aspects of the electric and gas properties operations in three states, including Arizona.

Q. Please describe your employment history with Citizens.

A. Prior to my current dual responsibilities for ELI and the Public Service Sector, I held the position of President of ELI, which I was appointed to in January 2002. Immediately preceding that assignment, I served as President of the Public Services

Sector. Other positions I have held in the Company include Vice President of Arizona Gas Operations and Manager of Special Projects for the Arizona Energy Division. Before coming to Arizona, I was the Manager of Electric Production in Citizens' Kauai Electric Division, responsible for all electric production, as well as system operations for the Island of Kauai.

Prior to working for Citizens, I was employed by the Long Island Lighting Company ("LILCO") in various positions, including Internal Combustion Engineer, Operation Engineer and Maintenance Engineer. Before working for LILCO, I was an employee of the United States Navy as a design engineer and the Babcock and Wilcox Company as a field engineer.

Q. Have you testified previously before a regulatory agency?

A. I have provided prefiled testimony in proceedings before the Vermont Public Service Commission and the Arizona Corporation Commission and have testified in proceedings before the Hawaii Public Utilities Commission and the Colorado Public Utilities Commission. I have also represented the Company at Arizona Corporation Commission Open Meetings.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide background information about Citizens' Arizona gas and electric operations, to describe Citizens' business plan to become solely a communications provider, and to emphasize that the sale of the gas and electric operations will have no negative effect on Citizens' customers.

Q. Please briefly describe the services provided by Citizens.

A. Citizens provides communications services and public services, including gas and electric distribution, to approximately 1.8 million customers in 21 states. Citizens also has ownership interests in cable television and cellular telephone companies.

Q. What services does Citizens provide in Arizona?

A. Citizens provides natural gas service through its Northern Arizona and Santa Cruz Gas Divisions and electric service through its Mohave and Santa Cruz Electric Divisions. Citizens also provides communications services through its three incumbent local exchange carriers, Citizens Telecommunications Company of the White Mountains, Inc., Citizens Utilities Rural Company, Inc., and Navajo Communications Company, Inc. Citizens also provides competitive local exchange services through ELI.

Q. How many customers does Citizens serve in Arizona?

A. Citizens serves approximately 367,500 customers in Arizona, largely in the state's rural areas. There are approximately 125,000 natural gas customers, 77,500 electric customers, and 165,000 telephone access lines.

Q. Please describe the Arizona natural gas operations.

A. Citizens natural gas operations are comprised of the Northern Arizona Gas Division ("NAGD") and the Santa Cruz Gas Division ("SCGD"). These Arizona gas operations serve customers in two distinct locations: a large geographic area in northern and western Arizona, and a smaller area in the southern part of the state. A map of our service area is attached as Exhibit DM-1.

The NAGD operation provides natural gas service to approximately 118,000 customers in portions of Coconino, Mohave, Navajo and Yavapai counties. This services area includes Flagstaff, Kingman, Prescott, Sedona, Show Low Cottonwood, Clarkdale, Village of Oak Creek, Verde Village, Pinetop-Lakeside, and Camp Verde.

The SCGD serves approximately 7,000 customers in Santa Cruz County. Santa Cruz County covers approximately 1,200 square miles and is located near the

Mexican border in the southern part of the state. Communities that SCGD serve include Nogales, Tubac, Patagonia, Kino Springs, and Rio Rico.

Ninety percent of Citizens' natural gas customers are residential, nine percent are commercial and the remaining one percent is transportation and industrial customers. Citizens is the second largest and the fastest growing natural gas company in Arizona. Customer growth in 2000 was over six percent, which is four times the industry average.

Q. Please describe the Arizona electric operations.

A. Citizens provides electric service through the Mohave Electric Division ("MED") and the Santa Cruz Electric Division ("SCED") - collectively referred to as the Arizona Electric Divisions ("AED"). The customers of the AED are located in and around three distinct areas - the City of Kingman and Lake Havasu City in Mohave County, and the City of Nogales in Santa Cruz County. The AED serves approximately 77,500 customers. A map of our electric service territory is attached as Exhibit DM-2.

The MED operation provides electric service to approximately 60,500 customers in portions of Mohave County. This service area includes Kingman, Lake Havasu, a portion of Bullhead City and several smaller communities throughout Mohave County.

The SCED serves approximately 17,000 customers in Santa Cruz County. Santa Cruz County is located near the Mexican border in the southern part of the state. Communities that SCED serve include Nogales, Tubac, Amado, and Rio Rico.

Eighty-four percent of Citizens' electric customers are residential, twelve percent are commercial and the remaining are public authority and industrial customers. Citizens is the third largest investor-owned company in Arizona. Customer growth in the year 2000 was over four percent.

Q. Why is Citizens divesting itself of its natural gas and electric operations?

A. Citizens owned and operated companies that provided communications, electric, gas, and water services for several decades. In the past, because the regulatory policies for both the public services and communications industries were similar, Citizens developed and operated under a common formula for overseeing and expanding its lines of business.

However, in recent years, the similarity between the public services business and the communications business has diminished. While the public service companies are largely regulated monopolies, the communications industry has become more competitive. Changes in regulatory policy, in technology and in the marketplace were the catalyst for Citizens' Board of Directors' May 1998 decision to separate Citizens into two stand-alone, publicly-traded companies.

In 1999, the Board of Directors changed Citizens' strategic direction, with the goal of becoming exclusively a communications company. Rather than split into two companies, Citizens' decided to divest its public services businesses to obtain funding for telecommunications acquisitions. During 2001, Citizens sold two natural gas operations—one in Colorado and one in Louisiana, and in January 2002 Citizens sold all of its water and wastewater treatment operations. In March 2002, the Company also sold its Kauai Electric Division.

Q. What process did Citizens use to select a buyer for its Arizona operations?

A. Citizens engaged the services of Morgan Stanley to advise Citizens' Board of Directors during the divestiture process. The process included screening of potential applicants, assisting in the due diligence reviews, and evaluation of the purchase price and terms of potential sales contracts. During this process, UniSource, with its major subsidiary Tucson Electric Power Company ("TEP"), was identified as an exceptional potential acquirer of our Arizona assets.

Q. Why did Citizens select UniSource to purchase the Arizona natural gas utility operations and its Arizona electric operations?

A. Citizens selected UniSource as the successful buyer for its Arizona gas and electric operations based on a combination of factors, including price, UniSource's financial resources and operational expertise, and its willingness to agree to the Purchase and Sale Agreement terms and conditions. Unisource's subsidiary, TEP, has expertise in providing electric service to customers in the State of Arizona. While UniSource does not currently have gas properties, the company offered gas service several years ago. In addition, natural gas service complements electric service, as both are energy services. Citizens is confident that UniSource, with TEP, its existing electric utility, and with the experience as a former provider of natural gas service, has the managerial and operational resources and expertise to continue providing high quality service to Citizens' Northern Arizona and Santa Cruz customers at reasonable prices. With TEP already serving customers in Arizona, Citizens believes that the transition of customers from Citizens to UniSource will be transparent. Thus, customers should see no impairment in the quality or reliability of their service.

Q. What are the public interest benefits of the sale of Citizens' Arizona operations to UniSource?

A. The sale of Citizens' Arizona natural gas and electric operations to UniSource serves the public interest in several ways. Its subsidiary, TEP, is currently a local public service company that has been serving customers in Arizona for decades. As a result, UniSource is familiar with the rules, regulations and business processes needed to successfully operate in Arizona. UniSource is committed to furnishing high quality and reliable electricity and natural gas services to its customers, and TEP has the operational personnel and management experience necessary to service Citizens' customers. UniSource's focus will continue to be the energy business, which will allow the continued delivery of safe, high quality, and reliable natural gas and electric service to Citizens' existing customers. For these reasons, Citizens believes that UniSource's acquisition will benefit customers and will thus serve the public interest.

Q. What impact will the sale to UniSource have on Citizens' employees?

A. Citizens has approximately 200 employees located within the State of Arizona. UniSource has indicated it intends to retain substantially all of those employees. Unisource representatives visited with all of Citizens' employees shortly following the announced acquisition. This will assure a smooth transition and continuation of service by knowledgeable employees. The employees will receive comparable salary, wages and benefits to those currently received from Citizens.

Q. What steps will Citizens and UniSource take to ensure that there are no service interruptions to gas and electric customers upon the transfer of operations to UniSource?

A. Citizens and UniSource have formed a number of transition teams. The goal of these teams is to identify and resolve any issues to ensure that there will be no interruptions to service. In addition, the companies have agreed to conduct an extensive public information campaign to educate the residents of all the affected communities regarding the transaction. This will include press releases, as well as public meetings in key locations in the service territories. In addition to these efforts, representatives from UniSource are in the process of contacting representatives in the areas currently being served by Citizens. UniSource has received a positive reception from all parties contacted.

Q. What will the effect of the sale of gas and electric properties have on the Arizona telecommunications customers?

A. If anything, the sale of the public service properties should benefit Arizona and all of Citizens' communications customers because without the public service companies, Citizens can concentrate on its core markets, maximize managerial and operational efficiencies, and maintain or improve service to customers. Customers of the Citizens' communications providers will continue to receive service from experienced telecommunications companies that are committed to providing safe, reliable, quality service at a reasonable cost.

Q. Do you have any concluding remarks?

A. Yes, I do. I strongly urge the Commission to approve the transfer of Citizens' Arizona natural gas and electric utility operations to UniSource, as specifically requested in the Joint Application filed by the parties in this proceeding. The record and evidence in this proceeding will demonstrate that the public interest is well served by such transfer and approval and that no harm or adverse impact to any customer will result. UniSource is an excellent entity to purchase Citizens' gas/electric operations within the State of Arizona.

Q. Does this conclude your testimony?

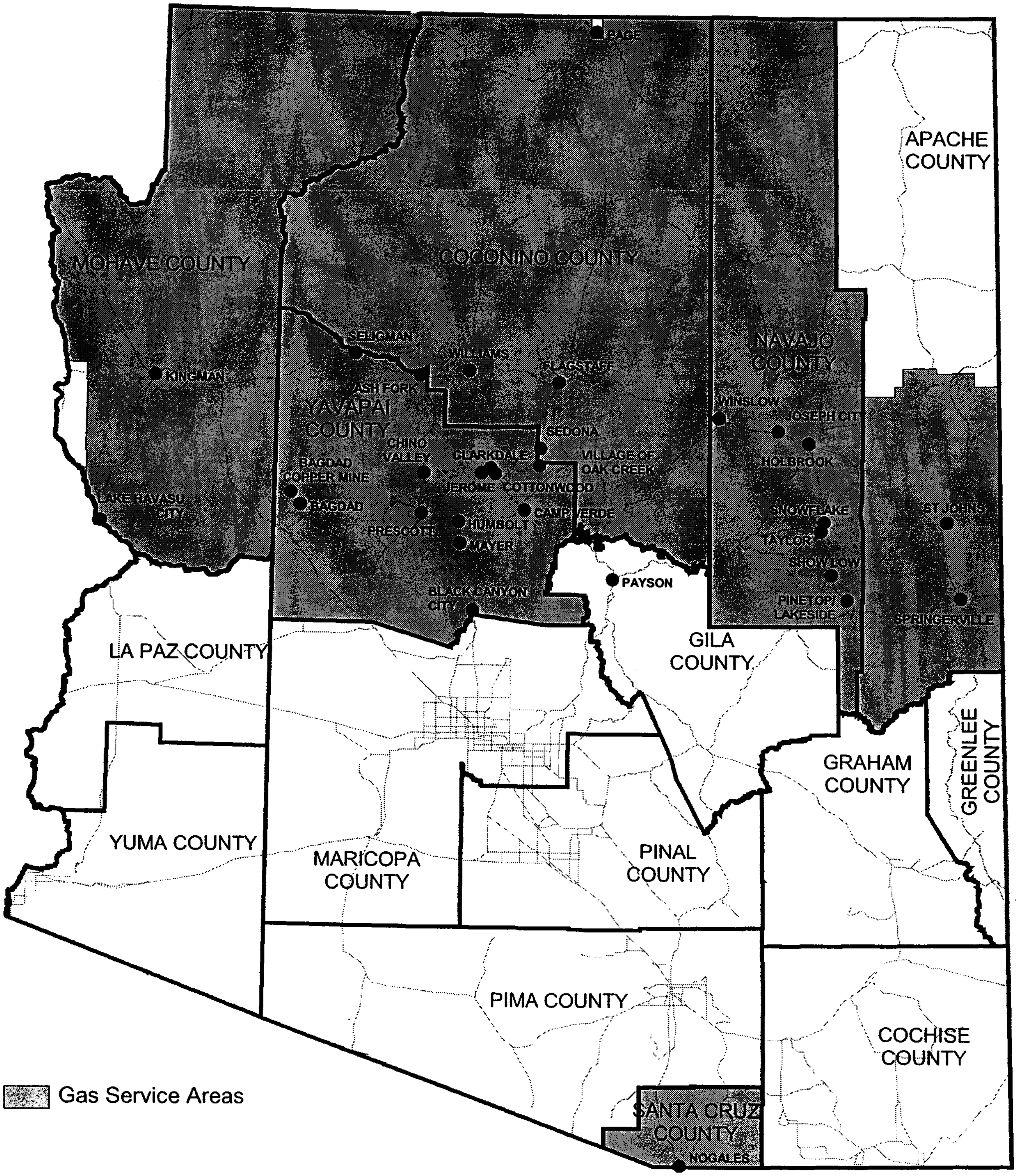
A. Yes it does.

1

Citizens Utility Company

DM-1

Arizona Gas Service Areas



N

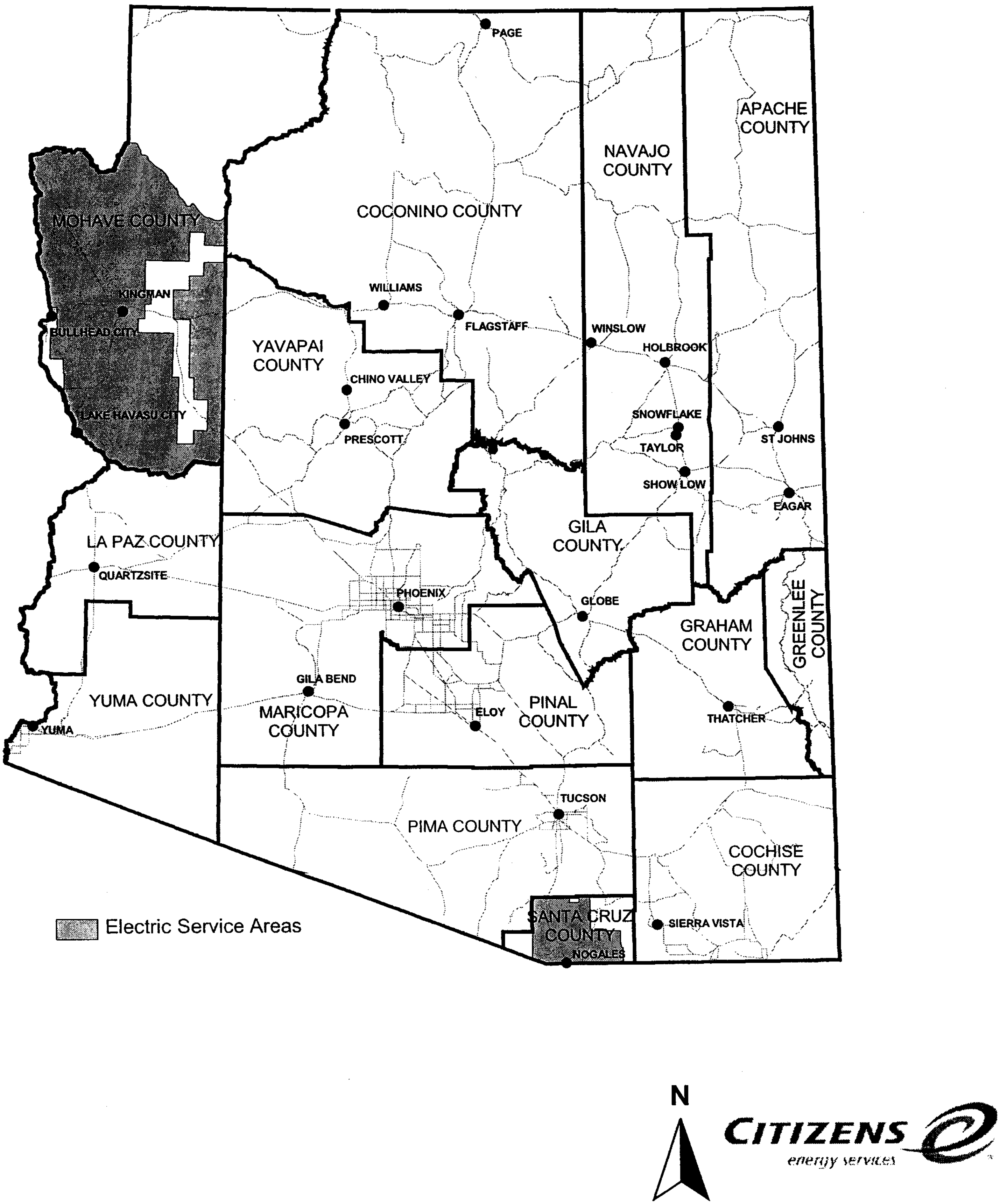
CITIZENS
energy services

2

Citizens Utility Company

DM-2

Arizona Electric Service Areas



INTRODUCTION

Q. Please state your name and business address.

A. My name is Kenneth L. Cohen. My business address is Citizens Communications Company, 1450 Poydras Street, Suite 1800, New Orleans, Louisiana 70112.

Q. By whom are you employed and in what capacity?

A. I am employed by Citizens Communications Company ("Citizens") as President and Chief Operating Officer of the Public Services Sector ("PSS").

QUALIFICATIONS

Q. Please describe your current duties and responsibilities.

A. My major responsibilities are: (1) to oversee all of Citizens' electric and gas operations, including the Arizona Gas Division; (2) to direct the PSS staff functions, such as Accounting and Finance; and (3) to manage the Public Service capital and operating budgets.

Q. Please summarize your educational background.

A. I attended Pace University in New York City and earned a BBA in Public Accounting. I hold CPA certificates issued by the Boards of Accountancy for the states of New York and Louisiana.

Q. Please describe your work experience.

A. I joined Citizens in August 1996 as Controller of the PSS, with responsibility for all the accounting books and records of Citizens' gas, electric, water, and wastewater properties. In November of 1999, I was promoted to Vice-President and Controller for Citizens. I was promoted to President and Chief Operating Officer of the PSS on January 1, 2002. Prior to joining

Citizens, I worked for KPMG Peat Marwick LLP in New York City from March 1987 through August 1996.

Q. What areas will you address in this testimony?

A. My testimony will address the Arizona Gas Division's ("AGD" or "Company") need for rate relief, the policy reasons for consolidating the Northern Arizona Gas Division ("NAGD") with the Santa Cruz Gas Division ("SCGD"), the PSS's accounting systems and procedures, and the potential sale of the AGD.

RATE RELIEF NECESSARY

Q. Why is AGD filing for a rate increase?

A. AGD is filing this rate case to recover the approximately 133 million dollars that the Company has invested in gross plant in Arizona from January 1, 1996 until December 31, 2001.

Q. What is the amount of the requested annual increase in gross revenues?

A. The requested increase in annual revenues is approximately $ 21 million or 28%. In order to mitigate the rate increase, the Company has asked Mr. Rosenberg to use the lower end of his cost of equity range in determining the overall cost of capital for AGD.

Q. For what purposes were these capital expenditures made?

A. Approximately $113 million of the capital expended is related to transmission and distribution assets. The vast majority of this is related to the extension of natural gas service to areas within Citizens' certificated area that had not previously had natural gas service and to repair and improve its existing system. The goal is to insure that our customers' current and future needs will be met in a safe and reliable manner.

Q. Why did Citizens expend so much capital to extend natural gas service in its certificated areas?

A. The "Build-Out" was initially ordered by the Arizona Corporation Commission ("Commission") in Decision No. 57647, as a condition of the Commission's approval of Citizens' acquisition of the Southern Union Gas property. Citizens subsequently submitted its "Build Out Plan" to extend natural gas service, which the Commission reviewed and approved. Mr. Gary Smith, Vice President of Gas Operations, has discussed the Build-Out Plan at length in his testimony.

Q. Are the capital expenditures the only basis for AGD's request for rate relief?

A. No. A review of AGD's operating cash flow for the years 1999 through 2001 shows a continuing trend of negative operating cash flow. Negative operating cash flow is Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA") less capital expenditures. The AGD had a $12 million negative operating cash flow in 1999, a $19 million negative operating cash flow in 2000 and another $15 million negative operating cash flow in 2001. The trend continued into July 2002. This deficit does not include the $39 million of deferred gas cost that AGD had incurred on behalf of its customers, but was not allowed to collect until September 2001, through its Purchased Gas Adjustor ("PGA") mechanism.

Q. Why hasn't AGD applied for a rate increase since 1996?

A. Clearly, with the significant capital investment made by the AGD in the last several years, AGD has a legitimate reason to request a rate increase. The reason the Company has not filed a rate case since 1996 is twofold: (1) In

Decision No 59875, the Commission adopted a settlement agreement where AGD agreed that no application for a general rate case would be filed before November 1, 1998; (2) In May 1999, Citizens changed its business direction, which postponed the filing of a rate application.

Q. What do you mean by "Citizens changed its business direction"?

A. In 1998, Citizens made a business decision to separate its public service business from its telecommunications business to permit the market to value the two different types of business appropriately. In 1999, the Board of Directors changed Citizens' strategic direction. The goal was to become exclusively a communications company. Citizens' strategy was to divest of the public service businesses to obtain funding for telecommunications acquisitions. At the outset Citizens did not realize that the process of separating and divesting would take longer than five years. Had this been anticipated, AGD would have applied for a rate increase earlier.

Q. What was the catalyst for the filing of the request for rate relief at this time?

A. Frankly, the rate case filing was made during the summer of 2002 because at a September 2001 Open Meeting, the Commissioners directed the AGD to make a mid-summer rate filing. This filing represents the Company's compliance with that directive.

Q. What test year is reflected in the Company's filing?

A. The application reflects a historical test year ending December 31, 2001.

CONSOLIDATION

Q. Are you filing separate rate requests for NAGD and SCGD?

A. No, we are filing a consolidated case.

Q. What are the policy reasons for Citizens consolidating NAGD with SCGD for purposes of this rate case?

A. Citizens believes that it is appropriate to consolidate NAGD and SCGD for operations, regulatory, and financial reasons. All of the gas operations in Arizona report through their management to the Vice President and General Manager of Arizona gas operations, Mr. Gary A. Smith. All of the gas facilities throughout Arizona are maintained and operated by Arizona Gas Division employees. The employees and all costs of operating the natural gas systems throughout the state are funded by the same AGD budget. As part of this filing, the Company has also standardized the tariffs for the Northern Arizona operations and the Santa Cruz operations, which will make the management of the tariffs more efficient and effective. The analyses of test year operations for purposes of developing an appropriate revenue requirement were conducted separately for the two properties, and the results were then combined into the various schedules presented in support of this combined rate application for AGD.

ACCOUNTING BOOKS AND RECORDS

Q. Are you familiar with the accounting books and records for the AGD?

A. Yes. Since August 1996, I have been responsible for all accounting books and records for the Citizens' Public Service properties, including NAGD and SCGD.

Q. Please provide a brief overview of the accounting for Arizona's gas properties.

A. The books are maintained in accordance with the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts and are a part of the PSO's fully integrated SAP financial system. SAP is comprised of general ledger and reporting, materials management, fixed assets, and project modules. PSO's payroll accounting function during the test year resided on a Peoplesoft system. As of January 1, 2002, the PSO payroll system was outsourced to Automated Data Processing ("ADP"). The customer billing for AGD is conducted on a recently implemented Orcom system. Direct access to all current AGD operating and financial information in the SAP, Orcom and ADP systems are available to the AGD personnel.

Q. Is AGD's accounting integrated with that of the rest of the PSS?

A. Yes. Accounting for AGD has been wholly integrated with the accounting on a property and sector level. There are no separate accounting systems used for the AGD. There is one financial suite, SAP, which incorporates data from specialized systems, such as the Orcom billing system used by AGD. Subject to certain security provisions, access to the SAP system is directly available from both the PSS and the operating divisions such as AGD.

ADMINISTRATIVE OFFICES/SERVICES PROVIDED

Q. Please describe the administrative offices that serve the PSS and explain the functions performed by each.

A. As Citizens' strategic direction has evolved in recent years, different administrative offices have assumed different roles. The Stamford Administrative Office ("SAO") provides oversight, leadership, and direction at the overall corporate level. With respect to accounting functions, SAO administers the cash management function, corporate consolidation, income taxes, and financial reporting. Other than those functions, the SAO has little involvement in day-to-day processing of transactions. SAO also provides Human Resource oversight, as well as corporate legal and regulatory services.

The Public Service Organization, located in New Orleans, performs and directs virtually all of the accounting functions for the PSS, which includes the Citizens' electric and gas properties. Control of the SAP system for the PSS resides at the PSO and is supported by employees of the PSO. The PSO maintains and manages the fixed assets system (including overheads), depreciation, accounts payable, and payroll, as well as the preparation of the annual FERC reports.

The services provided by the personnel at the Phoenix Administrative Office ("PAO") include legal, regulatory affairs, engineering, and administrative support. Costs of the PAO and its personnel are distributed similarly to those incurred at other administrative offices earlier identified. Most PAO costs are incurred in connection with activities performed on behalf of Arizona properties and are so distributed. Such costs are limited to payroll, payroll-related charges, and out-of-pocket expenses.

Q. Please describe the current process for recording charges to the NAGD and SCGD.

A. To establish the validity of costs and to ensure the accuracy and integrity of the accounting system, monthly reviews of the balance sheet and income statement are conducted. The monthly balance sheet review compares the current month balance with those of the prior month and with the prior year-end. The monthly income statement review contrasts the current month revenue and expense level with those reported for the same month during the prior year and with the operating budget. AGD personnel investigate variances to explain all significant fluctuations month-to-month and year-to-year, as well as any unusual recorded items. AGD sends summaries of its review to the PSO for further review. If, at any step in the process, an unintentional error is caught, the accounting staff will make an appropriate adjustment. During this review, a check is also made to ensure that any costs associated with non-regulated activities are appropriately excluded from regulated accounts.

Q. Has the Company reviewed its books of accounts and ensured that accounting records for all costs to be paid by Arizona Gas ratepayers are kept in conformance with GAAP and the FERC Uniform System of Accounts?

A. Yes, we have reviewed our books and records and I can attest that the books and records are kept in conformance with GAAP and the FERC Uniform System of Accounts.

POTENTIAL SALE OF GAS OPERATIONS

Q. Please explain Citizens' plans for reorganization as a communications company.

A. Please keep in mind that in discussing Citizens' plan for reorganizing, I am constrained by certain rules of the Securities Exchange Commission ("SEC") protecting confidential information. The following information has been previously disclosed to the public and therefore is permissible to discuss under the SEC rules. As noted above, Citizens made a business decision in 1999 to become solely a communications company. It is Citizens' intent to finance telecommunications acquisitions in the long-term through the disposition/sale of its interest in the public utilities services (i.e., water, wastewater, electric and gas operations).

Currently, Citizens is attempting to sell all of its non-telecommunications properties. It has been successful to date in selling its Louisiana Gas property, its Colorado Gas property, and its water/wastewater assets. In 2000, Citizens announced the sale of its Arizona and Vermont Electric properties, however the sale agreement was terminated in the second quarter of 2001. In March 2002, Citizens signed an amended and restated agreement to sell the Kauai Electric Division; that transaction is expected to close by the end of this year. With the sale of Kauai Electric, Citizens will have divested approximately 75% of its public service properties.

Citizens continues to negotiate with potential buyers for the remainder of its utility properties, including the AGD. Citizens will keep the Commission and Residential Utility Consumer Office appraised of any future developments regarding Arizona gas assets.

Q. In light of Citizens' express intention to sell the AGD, how can the Commission be assured that the current management will continue to fund the Arizona Gas operations at the level necessary to provide reliable energy service?

A. As President of the PSS, I recognize that Citizens has an obligation to provide safe and reliable service to its customers. I am here to attest that Citizens will continue to honor that responsibility while the gas properties are being offered for sale. Furthermore, providing safe and reliable service is a prudent business decision - Citizens would not want to take any action or fail to act in any way that might lessen the value of the property it is trying to sell.

Q. Are there any other matters you wish to address at this time?

A. It has become apparent that the AGD will continue to incur significant expenses that are not addressed in this rate application. Summer 2002 is not over yet, and there already have been forest fires in Prescott and Nogales areas, as well as the Rodeo-Chediski fire that destroyed hundreds of thousands of acres in Arizona's White Mountains. All of these areas are served by either NAGD or SCGD.

Q. How do these forest fires affect AGD's financial positions?

A. The Rodeo-Chediski fire illustrates how a natural disaster can affect a utility's bottom line. The Rodeo-Chediski fire destroyed hundreds of homes in NAGD's service territory, which means that these customers will not be using NAGD gas service. In turn, this means that the test-year revenues stated in the rate filing may not be representative of expected revenues for these parts of AGD. In addition, there are significant expenses for emergency operations as well as the costs to rebuild and repair damaged or destroyed facilities.

Q. Are these differences in revenues and expenses reflected in the rate filing?

A. No. They are not addressed in this rate application.

Q. Do you have a proposal regarding these forest fires?

A. Because Arizona has frequent forest fires during the summer, I do not think these fires should be characterized as extraordinary events. I believe it would be prudent to have funds set aside in a specific account that would be used only in the event of a disaster, natural or otherwise. While this concept has not been fully developed yet, and the full expense of the Rodeo-Chediski fire has not been fully calculated at this time, I would like the opportunity to bring a proposal to the Commission in the future.

Q. Does this conclude your testimony?

A. Yes.

S:\Deb~Docs\Az 02 Gas Rate Case\Testimony\Ken Cohen~Direct final

Revised July 29, 2002

EXHIBIT
JA-12
Admitted

INTRODUCTION

Q. Please state your name and business address.

A. My name is Gary A. Smith. My business address is 2901 West Shamrell Blvd., #110, Flagstaff, Arizona 86001.

Q. By whom and in what capacity are you employed?

A. I am employed by Citizens Communications Company ("Citizens") as Vice President and General Manager, Arizona Gas Division ("AGD" or "Company").

Q. What are your duties and responsibilities?

A. I am responsible for directing the Arizona operations of Citizens' natural gas business. Our service territory includes the northern third of the state, as well as Santa Cruz County in Southern Arizona. My chief responsibilities include oversight of the operations, maintenance, construction, and expansion of our gas systems. In addition, I have management responsibility for all of AGD, which has approximately 200 very dedicated employees.

Q. Please outline your educational background.

A. I have a Masters Degree in Information Systems American InterContinental University and a Bachelor of Science degree in Civil Engineering from Arizona State University. I also have an Associate of Arts Degrees in Fire Science Mesa County Community College and Emergency Medical Training from Monroe County Community College.

Q. Please state your work experience.

A. I have 24 years of public utility experience, including 20 years of senior management experience. I have been with AGD since August 1, 1998. Prior to my position at AGD, I worked at the Arizona Corporation Commission ("Commission") for 19 years. During my tenure at the Commission, I served as Chief of Safety (1988-1998) and Chief of Pipeline Safety (1983-1988).

Q. What is the purpose of your testimony in this proceeding?

A. My testimony will discuss this rate application and provide an overview of AGD and the communities that we serve. I will review operation issues, such as relocation of the Flagstaff office, transfer of a gas line in Nogales, and the demands of defending gas facilities from forest fire. I will also discuss the following:

- The Company's rationale in consolidating the NAGD and SCGD operations for purposes of this rate application;
- The significant capital expenditures made since the last rate application and the success of NAGD's Build Out Program.
- The Company's low-income programs.

CITIZENS' ARIZONA GAS DIVISION

Q. Please describe Citizens' AGD.

A. The AGD is comprised of Citizens Northern Arizona Gas Division ("NAGD") and Citizens Santa Cruz Gas Division ("SCGD"). These Arizona gas operations serve customers in two distinct locations: a large geographic area in Northern Arizona, and a smaller area in the southern part of the state. These counties comprise approximately 50% of Arizona's geographic area. Citizens' AGD is the second largest and fastest growing gas company in Arizona. Customer growth in 2000 was over 6%, which is four times the industry average. During 2001, AGD sold or transported over 12 billion cubic feet of gas and was one of the lowest cost energy suppliers in the state.

Q. What is the make-up of AGD's customers?

A. Ninety percent of AGD's customers are residential and nine percent are commercial, with transportation and industrial customers making up the remaining one percent. One of NAGD's more significant industrial customers is Griffith Energy Plant, a 600 megawatt ("mW") combined-cycle gas turbine electric generation facility in Mohave County, which began commercial operation in January 2002.

Q. What is the term of NAGD's Agreement with Griffith?

A. The Commission approved the special transportation agreement with Griffith in July 21, 1999, Commission Decision No. 61835. Under this twenty-year Transportation Agreement, NAGD constructed, owns, and operates pipeline facilities that connect the Griffith plant to two interstate pipelines, one owned by El Paso Nautural Gas company, the other owned by Transwestern Pipeline Company. The total cost to interconnect the pipelines was $5.9 million. As compensation for constructing and operating the two interconnections, Citizens receives a monthly payment based on levelized revenue requirements that reflect the plant investment, operating and maintenance expenses, depreciation, property taxes, income taxes, and return on investment, which is based on the current return authorized for the NAGD.

Pursuant to the Commission's order, the Company must remove all revenues and expenses associated with the Griffith contract from test year operating income, as well as all plant investments and related amounts from rate base in any future regulatory proceedings during the term of the contract. This adjustment has been made in this filing, as explained by Company witness Kevin Doherty in his testimony.

Q. Please provide more specific information about your operations in Northern Arizona.

A. The NAGD operation provides natural gas service to approximately 115,000 customers in portions of Coconino, Mohave, Navajo, and Yavapai counties. This service area includes the towns and cities of Flagstaff, Kingman, Prescott, Sedona, Show Low, Cottonwood, Clarkdale, Village of Oak Creek, Verde Village, Pinetop-Lakeside, and Camp Verde.

Q. How does that compare with your operations in Southern Arizona?

A. The SCGD serves approximately 7,000 customers in Santa Cruz County. Santa Cruz County covers approximately 1,200 square miles and is located near the Mexican border in the southern part of the state. Communities that SCGD serve include Nogales, Tubac, Patagonia, Kino Springs, and Rio Rico. Citizens' largest customer in the area is the Carondolet Holy Cross Hospital. Other commercial customers include a medical supply sterilization plant, hotels, restaurants, and schools.

Q. Can you describe AGD's distribution system?

A. The AGD has approximately 2,300 miles of distribution main lines and 124,000 service lines in its current distribution system. Since Citizens acquired the system in 1991, AGD has installed approximately 850 miles of distribution main lines and 50,176 service lines.

The AGD distribution system is interconnected with two separate interstate pipeline systems and AGD operates 30 interconnect points. The delivery pressures are set contractually, and range from 200 pressure per square inch gauged ("PSIG") to 1000 PSIG.

Q. The natural gas industry seems to be so heavily regulated ? Why is that?

A. Natural gas is volatile, and can be explosive if not handled correctly. For those reasons, there are stringent safety standards with which a gas operator must comply. Arizona's gas operations are required to comply with the federal Natural Gas Pipeline Safety Act of 1979; the federal Hazardous Liquid Pipeline Safety Act of 1979; and Arizona's Pipeline Safe statutes, A.R.S. § 40-441 et seq.

Q. Does Citizens' Arizona gas facilities meet these safety requirements?

A. Yes, in fact in some areas, the Citizens' safety standard is more stringent that the federal standard.

Q. Can you give an example?

A. The distribution system in Arizona is primarily new and well maintained. Approximately 54% of the system is steel and the remainder is plastic pipe. AGD has an on-going cathodic protection program for its steel distribution system. Cathodic protection is a technique to prevent the corrosion of a metal surface by making that surface the cathode of an electrochemical cell. As a result, the effect of corrosion has been mitigated, substantially reducing the replacement of those systems. In addition, AGD has a continual leak survey program and implemented more stringent classifications than under the federal safety regulation. This approach has greatly reduced the risk of hazard and significantly reduced the unaccounted gas, which is reported annually.

RATE APPLICATION

Q. When was the last rate increase approved by the Commission for Citizens' AGD?

A. In October 1996, the Commission issued Decision No. 59875, which provided for a $2.7 million annual increase in revenues for NAGD. In June 1987, the Commission issued Decision No. 55585, which reduced the annual operating revenues for the SCGD operations by approximately $87,000.

Q. Why is AGD filing a general rate increase application at this time?

A. There are two principle reasons for the filing of this rate application at this time. One reason is based on a business decision; the other reason for filing at this time is to comply with a Commission directive.

Since the last rate cases for Citizens' AGD properties, the Company has expended significant capital investment funds and incurred significantly increased operating expenses. The Company has made substantial additions to utility plant and equipment to serve existing customers and to meet customer growth. Both NAGD and SCGD's operating expenses have increased significantly. The increased capital and operating costs have exceeded the growth in sales and revenues. The requested rate increases are required to recognize the increased investment and operating expenses and to provide the Company with a reasonable opportunity to realize a fair rate of return.

The reason for filing this rate case at this time is to comply with the Commission's directive. At the September 2001 Open Meeting, the NAGD sought approval to implement an increase in its Purchase Gas Adjustor ("PGA"). At that time, the Commission directed Citizens to file a rate case for its gas properties. That directive was the catalyst for the rate application filing at this time. Company witness, Ray Mason, presents a comprehensive overview of Citizens' application in his testimony.

Q. Please describe the significant capital investment made by the Company since the last rate cases.

A. Since 1996, the Company has expended approximately $113 million on its transmission and distribution facilities. Most of this investment has been to upgrade and expand and reinforce its natural gas system in a number of communities in both Northern and Southern Arizona.

Q. In addition to the significant increase in rate base, were there other elements that contributed to the filing of this rate application?

A. Since the last rate cases, there have been increases in operating expenses, depreciation, and taxes that have exceeded revenues and sales.

CONSOLIDATION OF NAGD AND SCGD

Q. Why is the Company proposing to consolidate its two Arizona gas divisions?

A. The case is a consolidated filing for a number of reasons. All Arizona gas facilities are maintained and operated by the Arizona Gas Division employees, and all gas operations costs are funded by the same Arizona Gas Division budget. The proposed tariffs that are being filed with this case will be standardized for the Northern Arizona and Santa Cruz operation – which will make administration and management of the tariffs more efficient and effective. In addition, the Low Income Programs would be extended to Santa Cruz Gas Division customers.

Q. Did standardizing the tariffs result in any significant changes to the tariffs?

A. The services, terms, and conditions for most customers will not change significantly. However, because Citizens is proposing that the gas properties be consolidated, the services, terms, and conditions for customers located in SCGD would be identical to those applicable to customers in the NAGD. A more detailed explanation of the changes proposed in the rates and tariffs is contained in the testimony of Company witness James Harrison.

BUILD OUT PROGRAM

Q. What was the catalyst for Citizens to make significant capital investment to extend natural gas service?

A. The Commission approved Citizens' acquisition of the assets and certificates of convenience and necessity of Southern Union Company in December 1991. Those assets and certificates now comprise Citizens' NAGD. A key element of the approval was the requirement that Citizens provide the Commission with a long-term plan, of at least five years duration, for the expansion of natural gas service into certain previously unserved portions of the acquired certificated areas.

The objective of the "Build Out Program" was two-fold; first, to reinforce certain facilities purchased from Southern Union Gas that did not have adequate capacity to maintain service in all weather conditions; and second, to expand the delivery systems in order to serve a number of communities that desired natural gas service.

Citizens developed a comprehensive plan to invest substantial additional capital to extend natural gas service to the public in areas in NAGD's service territory that were not being served. The Company submitted its proposed Build Out Program to the Commission for approval in July 1993. The Commission reviewed and approved the Build Out Program in Decision No. 57647, which was issued in June 1994.

Q. Please describe the NAGD's Build Out Program.

A. As part of the Build Out Program, specific areas where natural gas service was not available were targeted for expansion. To ensure that the new customers carried the cost of the new facilities, the new customers in communities where service was extended paid a surcharge known as the "New Service Area Multiplier" ("NSAM") rate. The NSAM was equal to 150% of the applicable sales rate schedule on which a customer would otherwise be placed.

Q. What was included in the Build Out Program?

A. The Build Out Program included the reinforcement of the existing infrastructure, as well as the necessary expenditures for pipeline mains and service lines to extend natural gas service to homes and businesses in portions of the NAGD's service area that did not have natural gas service. Maintenance and repair of the overall system added to the reinforcement efforts. The required expenditures more than doubled NAGD's investment in gas plant facilities in northern Arizona.

Q. Can you describe what the reinforcement effort of the Build Out Program entailed?

A. Yes. The Build Out Program plan contemplated that the natural gas system that was in-service at that time would be reinforced. These reinforcements were intended to make better service available to the current customer base and at the same time provide capacity for the new customer base. The Company intended to accommodate customer growth both in the Build Out areas and through expansion of the distribution system that was already in place.

A good example of NAGD's reinforcement effort is the twelve miles of new pipeline from the Cottonwood Station, which traversed across the desert for approximately eight miles before reaching the Village of Oak Creek where it provided natural gas service. This project began by reinforcing the El Paso supply line that served the Cottonwood distribution system. Clearly, reinforcement of the existing system benefited current customers and also supported the expansion of NAGD's natural gas system.

Q. It's clear that the Build Out Program took longer than the initial five-year plan. Why?

A. There are several reasons the Build Out Plan took longer than originally anticipated. The level of complexity and difficulty in acquiring permits and easements required more time than had been expected. Also, the level of environmental mitigation measures required by the various federal, state, county, city-permitting agencies, and by private property owners were far greater than originally contemplated. It took longer than originally expected as a result of delays in obtaining construction permits and rights-of-way from the U.S. Forest Service, the State of Arizona, and private landowners. In addition, the demand for new natural gas service connections in and around existing Citizens' facilities were considerable and exceeded the Company's forecasts.

The AGD had not anticipated the number of requests for services in other "non-NSAM" areas and those requests proved a challenge for the Company, as well as its contractor's work force. For every one NSAM customer added, over six non-NSAM customers were added during the period that the AGD was implementing the Build Out Program.

Q. What is the status of the Build Out Program?

A. The Commission reaffirmed the continuation of NSAM premiums in 1996, Decision No. 59875. The project was completed on December 31, 2001.

Q. Is the Company still collecting the NSAM rates?

A. No, the NSAM was discontinued December 31, 2001, in conjunction with the completion of the Build Out Program. A notification of such termination was filed with the Commission's Director of Utilities. NSAM premiums billed to customers have been

removed by a proforma adjustment from test year revenues in this rate case. This adjustment is reflected in Mr. Kevin Doherty's testimony.

Q. Was the Build Out Program successful?

A. Yes, very much so. The Company believes it met both of its original objectives: 1) to reinforce certain facilities purchased from Southern Union Gas that did not have adequate capacity to maintain service in all weather conditions; and 2) to expand the delivery systems in order to serve a number of communities that desired natural gas service. The AGD has significantly improved system reliability and expanded gas service to nine communities not previously served. In addition, NAGD has added approximately 42,000 new customers.

Q. Where can more specific information regarding the Build Out be found?

A. As can be expected, a major expansion project in several areas of the state is a significant undertaking. Citizens filed a detailed Build Out Report with the Commission in October 2001. That report, Exhibit GAS-1, is in a separate notebook, Volume 8 of this filing.

LOW- INCOME PROGRAMS

Q. Please describe the low-income programs that the Company currently sponsors.

A. Currently, there are two low-income programs available for customers in Northern Arizona, the CARES program and the Warm Spirit program.

Q. What is the CARES Program?

A. The Citizens Assistance Residential Energy Support or "CARES" program provides financial assistance to certain residential customers to help them pay their gas bills. In cooperation with the Arizona Department of Economic Security, qualifying customers are entitled to prescribed discounts on their bills for gas service.

Q. How does the Warm Spirit Program assist low income customers?

A. For several years the NAGD has had a "Warm Spirit Program". This was created to permit existing customers to voluntarily contribute to a fund established for the purpose of assisting low-income customers with the payment of their gas bills. Amounts collected are to be directed to designated non-profit agencies for disbursal in the various communities served.

Q. Please explain the proposed changes to the low-income CARES rates.

A. The present CARES rate offers a 15% discount to low-income customers with incomes less than 150% of the poverty level. The discount is given to the first 100 therms of usage in the five winter months of November to March. The CARES Medical program increases the discount to 20% for eligible low-income customers. The proposed CARES program combines the two programs into one offering - a 20% discount for the first 100 therms of usage in six winter months including April. The rate is stated as a flat $0.15 per therm discount to eligible consumption rather than as a percentage discount. In this manner, a customer's annual discount can be estimated without estimating future gas prices.

Q. Will the Company's low-income program be affected by the consolidation?

A. One of the expected benefits of the proposed consolidation of the tariffs will be the expansion of the CARES low-income discount program to eligible customers in Santa Cruz County.

TRANSFER OF HIGH PRESSURE PIPELINE IN NOGALES

Q. Does the AGD own all the Company's gas facilities in the state?

A. The AGD currently owns all the gas facilities. Previously Citizens Santa Cruz Electric owned three miles of six-inch high-pressure natural gas pipeline that fed into its generating turbines at the Valencia Power Plant in Nogales, Arizona. Santa Cruz Electric has recently conveyed these gas facilities and the associated land and land rights to SCGD.

Q. Why did the Arizona Electric Division transfer this asset to SCGD?

A. Citizens has made a business decision to transfer the gas facilities to the SCGD so all gas operations are under the entity that has the knowledge and experience to operate a natural gas pipeline and remain in compliance with stringent safety requirements. As part of that conveyance, SCGD has assumed all obligations imposed by state or federal regulatory authorities related to the ownership of the gas facilities. SCGD will also be responsible for all federal, state, county, municipalities, foreign or other taxing jurisdiction sales, property, use, transfer, gross receipts, consumer levy, privilege or similar taxes, duties or governmental charges.

Citizens has made the appropriate accounting adjustments to reflect the transfer to SCGD from the Arizona Electric Division, as discussed by Company witness Kevin Doherty in his testimony.

OFFICE FACILITIES

Q. Did the administrative staff in Flagstaff move to a new office?

A. In June 2002, the administrative personnel for Citizens' AGD Operations relocated from its office building on Yale Street in Flagstaff, to less expensive leased facilities located near the Flagstaff municipal airport. The new headquarters for Northern

Arizona Gas, located in the Airport Industrial Park, is smaller and less costly than the previously occupied building on Yale Street. The move reflects a Company decision intended to cut costs and keep ratepayers rates as low as possible.

Q. Why did the Company move from the Yale Street Building?

A. The Yale Street Building had served as the regional headquarters for Citizens' gas, electric, and water operations for several years. However, Citizens has divested itself of the water and wastewater properties, and many of its gas properties outside Arizona. The result was that the Yale Street Building had many empty offices, which were neither "used" nor "useful".

Q. Has the effect of the move from the Yale Street building been reflected in the Company's rate application?

A. As explained in the testimony of Company witness Kevin Doherty, the net book value of the Yale Street office building has been removed from the respective plant accounts. Correspondingly, an amount equivalent to the annual lease payments associated with the newly occupied property has been included in test year operating expenses.

ARIZONA'S SUMMER FOREST FIRES

Q. Have AGD's service territories been affected by the forest fires that have broken out through-out the state this summer?

A. Yes, our operations have been significantly affected by forest fires. The summer of 2002 is not yet over, and the AGD has already experienced forest fires in Nogales, Prescott, and in the White Mountains, where Arizona's worst forest fire, the Rodeo-Chediski fire, raged through our service areas for almost two weeks.

Q. How did the Arizona gas operations respond to the Rodeo-Chediski fire?

A. The fire began on Tuesday, June 18th. For the AGD, there were critical safety concerns because of the volatility of natural gas, and its explosive nature when exposed to fire. Citizens Gas personnel devised strategic plans on how to isolate the area and valve off segments of the gas main. The town of Show Low remained on alert for evacuation for a number of days. When commercial activities were shut down in Show Low, gas operations set up a command center in Taylor. Citizens employees – management, technicians, field operations, information technology and administrative personnel - gave full support to the company's needs.

For gas operations, with the fire approaching very quickly, all personnel were required to wear Nomex clothing, carry radios and work on the "buddy–system" in the field. Field personnel were assigned to inspect all above ground facilities and regulator stations in the affected areas. Records and all essential operating and customer service data were loaded into evacuation vehicles.

On Saturday, June 22nd, the fire made a rapid advance towards Show Low. By 7:00 p.m. that night, the town was ordered to evacuate. Gas field personnel were directed to isolate the west side of Show Low at 7:51 p.m. The valves were shut off, and approximately 800 customer residences were affected. Personnel were then reassigned to the next phase in the isolation plan.

The following day, teams were set in motion to recover equipment, coordinate fire support, and to protect the company facilities. Gas management personnel had sand brought in to bury certain above ground gas facilities and operating pressures at certain facilities were lowered. Navopache Regional Medical Center Hospital was the only emergency medical facility in the area, and depended on the natural gas service for many essential services. Plans were made to keep the gas on to the hospital as long as possible.

Q. How did the gas operations personnel handle the re-entry of residents into Show Low?

A. By Wednesday, June 25th, it appeared that the fire would not advance into Show Low. Gas operations personnel began to restore the system facilities and patrols were sent out to monitor the areas. On Saturday, June 28th, the evacuation for Show Low and Pinetop/Lakeside was lifted. The gas operations crews were waiting in the affected areas as residents arrived and began re-lighting pilot lights, so the natural gas could flow into their homes. By July 9, 2002 almost every customer of the 1,200 in that region had gas service restored

Q. What was the financial impact of the fire on the AGD?

A. The full financial impact has not yet been fully realized. The Company spent thousands of dollars to provide supplies to the crews who were working to protect our gas facilities within the fire's grasp. Replacement of facilities, payment of overtime, and relocation from the Show Low offices were unplanned expenses. In addition, hundreds of homes were destroyed. It is simply too early to determine the full extent of the financial impact. Suffice it to say that the impact is significant.

Q. What were the "lessons learned" from the Rodeo-Chediski fire?

A. All in all, Citizens worked to protect life and safety first, and then property. Citizens' employees logged in a total of 2,525 extra hours to assist their customers and neighbors in these communities. It has become painfully clear to us that forest fires in rural Arizona are almost expected during our dry summers, and the devastation can be indescribable. We are aware that during the Rodeo-Chediski fire we had time to plan, but that may not always be the case. As a result, we are developing an emergency management plan that will address the necessary steps to take, so that we will be prepared to avoid disaster.

STATUS OF PUBLIC SERVICE ORGANIZATION ASSET SALES

Q. A few years ago, Citizens announced that it intended to sell all of its public service companies to fund telecommunications acquisitions. Are the AGD properties still for sale?

A. Yes.

Q. How does the potential sale of the AGD effect the day-to-day operations?

A. A possible sale of Citizens' Arizona gas properties at some future date does not affect the Company's day-to-day operations. The Company recognizes that it has the obligation to provide safe and reliable service to all of its customers, and it will continue to do so. This rate filing represents a business-as-usual practice. The requested increase in rates is long overdue. The Commission must approve all utility system sales in Arizona, and historically the provision of safe, reliable service has been a key element in that decision-making process.

Q. Does this complete your direct testimony in this proceeding?

A. Yes, it does.

EXHIBIT
JA-13
admitted

INTRODUCTION

Q. Please state your name.

A. My name is John A Cogan.

Q. By whom are you employed?

A. I am the Managing Member of The Johnco Group, LLC, a consulting company that offers a variety of services to companies in the natural gas industry. These services include the negotiation, acquisition, and management of natural gas supplies and delivery services.

Q. Please provide a description of your education and work experience.

A. I am a graduate of Southeastern Louisiana University with a Bachelor of Arts degree in Business Administration. For 32 years, I worked with Louisiana Gas Service Company, the predecessor to Citizens Communications Company. I retired from Citizens Utilities Company as Assistant Vice President of Energy Supply in December 1999. I have an extensive background in natural gas distribution operations and management, gas supply planning and procurement, gas utility and interstate pipeline regulation, utility accounting and information systems. During the last 16 years, I worked extensively in the regulatory arena, both state and federal, as well as focusing on natural gas supply planning and large volume customer contracting. I have testified as an expert witness on gas supply issues before the state regulatory commissions in Arizona, Colorado, and Montana, and as well as the Federal Energy Regulatory Commission ("FERC"). I also have served as a member of working groups addressing the development of gas purchase and recovery rules in the states of Arizona, Colorado, and Louisiana and a working group addressing gas utility unbundling in the state of Colorado. I have worked as an independent consultant since I retired in 1999.

Q. On whose behalf are you presenting testimony in this proceeding?

A. I am testifying on behalf of the Arizona Gas Division ("AGD" or "Company") of Citizens Communications Company ("Citizens"). The Arizona Gas Division consists of Northern Arizona Gas Division ('NAGD") and Santa Cruz Gas Division ('SCGD").

Q. Have you previously testified before the Arizona Corporation Commission ("Commission") on behalf of Citizens?

A. Yes.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is threefold. First, I will address certain changes to the AGD T-1 Transportation of Customer-Secured Gas tariff ("Transportation Service"). I will then address the AGD's Negotiated Sales Program ("NSP") and discuss the sharing of revenues that exceed the cost of service between the Company and its customers. Finally, I will address how the Company's base cost of gas was determined.

Q. Are you sponsoring any exhibits in conjunction with your testimony in this proceeding?

A. Yes, I am sponsoring Exhibits Nos. JAC-1 through JAC-13. These exhibits address the following areas:

JAC-1 Revised Tariff for Transportation of Customer-Secured Natural Gas ("T-1 Transportation Tariff").

JAC-2 FERC El Paso Natural Gas Company Order on Capacity Allocation and Complaints, issued May 31, 2002.

JAC-3	Arizona Corporation Commission ("ACC") Decision No. 59399 regarding Negotiated Sales Program ("NSP").
JAC-4	Citizens Application for Formal NSP Review, Docket No. E-1032-97-345.
JAC-5	ACC Decision No. 60423 regarding Formal NSP Review.
JAC-6	ACC Staff Memorandum regarding Formal NSP Review, Docket No. E-1032-97-345.
JAC-7	2000 and 2001 NSP Margin Analysis.
JAC–8	NAGD Purchase Gas Cost
JAC–9	SCGD Purchase Gas Cost
JAC-10	AGD Purchase Gas Forecast ("Requirements").
JAC-11	AGD – NAGD & SCGD Loss & Unaccounted For Gas ("L&U") Reports.

Q. Were Exhibit Nos. JAC-1 through JAC-11 prepared by you or under your direct supervision?

A. I prepared Exhibit Nos. JAC-1, and JAC-7 through JAC-10. JAC-2 through JAC-6 are public records and are provided for convenience of the parties. The remaining exhibit, JAC-11, was prepared under my direction for the Company.

THE CURRENT T-1 TRANSPORTATION SERVICE

Q. Please provide an overview of the current Company's transportation tariff.

A. The current T-1 Transportation Tariff, which has been approved by the Commission, requires that the customer and the Company execute a transportation agreement. The T-1 Transportation Tariff rates for this service consist of a basic customer charge per meter and a volume charge applicable to each therm of gas metered and delivered to the customer.

The transportation agreement, which may vary among customers, specifies the quantity of gas to be transported, the term, the otherwise applicable rate schedule, and any other special provision that the parties deem necessary. Under this T-1 Transportation Tariff, the Company will transport gas for an eligible customer that has independently secured gas. The gas will be transported from the point of interconnection between the Company's system and an upstream pipeline ("Receipt Point") and the customer's meter on the Company's distribution system ("Delivery Point").

Q. Under what conditions is a customer eligible for service under the current T-1 Transportation Tariff?

A. The following conditions must exist for a customer to be eligible for service under this tariff:

1. The Company has the distribution system capacity available to provide the requested service without constructing additional facilities.
2. The customer has demonstrated to the Company that it has assured natural gas supplies and upstream pipeline transportation for a term compatible with the service being requested.
3. The customer will be the end-user under the executed transportation agreement.
4. The volume of gas to be transported for the customer is greater than 120,000 therms per year.

Q. What responsibilities does the Company have under the current T-1 Transportation Tariff?

A. The Company is responsible for transporting the quantity of gas delivered on the customer's behalf from the Receipt Point to the customer's Delivery Point.

Q. What responsibilities does the customer have under the current T-1 Transportation Tariff?

A. The customer is responsible for procuring its own natural gas and having it delivered to the Company at the Receipt Point. To meet its daily requirements at the Delivery Point, the customer must secure upstream pipeline capacity directly or through capacity of its third party supplier. Additionally, the customer must comply with the Company's operating procedures for the scheduling and balancing of gas at and between the Receipt and Delivery Points.

Q. Under the current T-1 Transportation Tariff, can service be interrupted?

A. Although the Company has the responsibility to transport on a firm basis, there are limited circumstances where the service can be interrupted. This service can be interrupted: 1) during a period of curtailment, in accordance with the Company's curtailment procedures; 2) when the Company determines that it has insufficient capacity on its system or from its upstream pipeline; or 3) the customer's gas supply to the Company at the Receipt Point is insufficient to meet the customer's requirements at the Delivery Point.

Q. Is it a customer requirement that the quantity of gas delivered to the Receipt Point equal the quantity of gas taken by the customer at the Delivery Point?

A. The Company recognizes that it is not always possible to have quantities of gas at the Receipt Point match exactly to the quantity of gas consumed by the customer at the Delivery Point. Therefore, the T-1 Transportation Tariff provides some flexibility for the customer. Except during periods of curtailment, the customer may have up to a 25% variance between Receipt Points and Delivery Points on a daily basis. However, on a monthly basis, the goal is that the monthly variance would be as near to zero as practicable. Treatment of these variances is referred to as "balancing".

Q. How is the customer affected during periods of curtailment?

A. During periods of curtailment when the customer is not curtailed, the customer's consumption at the Delivery Point is limited to only that quantity of gas that is delivered on the customer's behalf at the Receipt Point.

Q. Does the Company currently offer a back-up service, in the event a T-1 transportation customer's gas supply to the Receipt Point is interrupted, or is insufficient to meet its requirements?

A. In addition to the balancing flexibility that is provided under the Company's operating procedures (which is described above), the customer has the option to subscribe to Back-Up Service. If a customer subscribes to Back-Up Service, the customer elects a specified quantity of gas and the Company maintains sufficient upstream pipeline capacity and gas supplies to provide for the delivery of that amount of gas when the customer's supply is interrupted or insufficient to meet its requirements. The gas delivered under this service is limited to the specific quantity of gas elected by the customer.

Q. Is there a charge for Back-Up Service?

A. Yes. Each customer electing Back-Up Service pays a reservation charge. This reservation charge is calculated by multiplying the reservation rate by the daily quantity of gas subscribed to for Back-Up Service. In addition, the customer pays the tariffed commodity charge on each unit of gas that is actually delivered by the Company to the customer. All amounts collected for this service are credited to Account No. 191, Deferred Gas Cost Account.

Q. Does a customer subscribing to the transportation service have to commit to a minimum term of service?

A. Yes, a customer requesting T-1 Transportation Service must enter into a transportation agreement for a minimum term of (12) twelve months.

Q. Upon termination of the transportation agreement, can a T-1 transportation customer return to receiving a tariffed sales service?

A. Yes, at the end of twelve months, a transportation customer may elect to receive service under the AGD's sales tariff.

Q. Pursuant to the AGD tariffs that are currently in place, must a former T-1 transportation customer that is currently under a tariffed sales service remain on the sales tariffed rate for a minimum term period?

A. No. Although a customer must take transportation service for a minimum term of 12 months, there is no corresponding minimum term for a customer who elects to convert back to a tariffed sales service upon termination of the T-1 Transportation Service.

Q. In addition to the eligibility requirements discussed above, is a sales customer converting to T-1 Transportation Service subject to any other conditions?

A. Yes. A customer converting from tariffed sales service to T-1 Transportation Service must provide the Company with a service change request. The customer is also subject to the following conditions:

1. Conversion to T-1 Transportation Service will occur at the beginning of the first calendar month that follows at least five days after the receipt of the customer service change request.
2. A sales customer that reverts to T-1 Transportation Service is subject to being billed or credited, based upon the customer's pro rata share of the balance in the Company's Gas Cost Adjustment bank.

PROPOSED CHANGES TO THE T-1 TRANSPORTATION TARIFF

Q. What changes or modifications to this rate schedule is the Company proposing?

A. As discussed in Mr. Harrison's testimony, the Company has submitted proposed tariffs for approval as part of this rate filing. Those proposed tariffs would standardize service offering for both NAGD and SCGD customers. A result of this standardization of Company tariffs is that the T-1 Transportation Tariff will be available for Santa Cruz Gas Division customers. Attached to my testimony, Exhibit No. JAC-1, is the proposed revised Transportation Of Customer-Secured Gas T-1 Tariff. The proposed revisions to this schedule can be summarized as follows:

1) The aggregation of customer meters would be allowed to meet eligibility requirements;
2) Back-Up Service would be eliminated;

3) Balancing procedures would be revised and a balancing charge would be implemented; and

4) Miscellaneous other charges are set out in detail.

Q. Please describe the proposed change in the eligibility requirements?

A. Under the current tariff, a customer must transport more than 120,000 therms per year to be eligible. While the Company believes that the current tariff provides for the aggregation of multiple meters serving the same customer at one location, it is unclear as to the customers' right and the Company's obligation as it relates to multiple locations. To clarify these rights and obligations, the Company proposes to modify Section 1 of the tariff. With this change, a customer may aggregate multiple meters at a single or multiple locations throughout the Company's gas system to satisfy the 120,000 therms per year eligibility requirement. However, only meters with an annual delivery quantity of 50,000 or more therms per year would qualify under this aggregate approach and eligibility of multiple service locations would be limited to those owned and operated by the same entity.

Under this proposal, customers that choose to aggregate meters would be charged the same tariffed volume charge for gas delivered through each meter as if they did not aggregate. The charge would be the unit sales margin for each therm, as set forth in the customer's otherwise applicable sales tariff. By applying this charge in this manner, a customer aggregating would be able to seek competitive gas commodity and pipeline transportation, but would pay the same cost of service rate that it would have paid as a tariffed sales customer.

Q. Is the Company proposing any change to the minimum annual transportation quantity eligibility requirement?

A. No, it is not.

Q. What change is the Company proposing to the Back-Up Service?

A. I described the Back-Up Service previously in this testimony. In this filing, the Company is proposing to eliminate this service.

Q. Why is the Company proposing to eliminate this service?

A. There are two basic reasons for the Company's proposal. First, since the inception of this service, the Company has never been required to make a delivery on behalf of a customer because of an interruption of the customer's secured gas at the Receipt Point. Secondly, the Company's ability to secure adequate pipeline capacity to provide this service is highly questionable since FERC recently issued its May 31st order that eliminates the full-requirement nature of the Company's upstream pipeline capacity from El Paso Natural Gas Company ("FERC El Paso Order"). A copy of this order is provided for the parties' convenience as Exhibit No. JAC-2.

Q. How many current customers have contracted for the Back-Up Service?

A. Currently, only four transportation customers out of twenty have contracts for this service.

Q. What amount was credited to the deferred gas cost account for this service during the test year?

A. During the test year, revenues from the Back-Up Service totaled $29,351. This amount was credited to the Deferred Gas Cost Account.

Q. How does the FERC El Paso Order impact the full-requirement aspect of the Company's contract?

A. Under its full-requirements contract with El Paso, the Company has the right to receive, and El Paso has the obligation to deliver, the daily needs of the Company's distribution system served by El Paso. It should be noted that, while Citizens is the actual signatory on this contract, for purposes of this testimony, I am referring to it as the AGD's contract, since the AGD is the division implicated by the contract. For several years, AGD representatives have participated in the regulatory proceeding before FERC that addressed the allocation of pipeline capacity on the El Paso interstate pipeline system. At issue, among other things, was El Paso's lack of pipeline capacity to meet the contractual obligations on its system. When available pipeline capacity is less than the firm contract demand on its system, El Paso prorates or rations its pipeline capacity based on a contract quantity. The Company, and most other El Paso customers located east of the California border, has full-requirement contracts. During periods when El Paso is rationing its pipeline capacity, the nominations of the AGD and other full requirement customers are limited only by the capability of physical pipeline facilities to deliver their full requirements. Customers that have a specific contract quantity stated in their contract are limited to nominations that cannot exceed their contract quantity. When such proration occurs, many shippers are not able to flow the gas that they nominate. In the FERC proceeding, El Paso's contract demand customers, as well as the FERC's staff, recommended that the FERC use its authority to abrogate the full requirement contracts and convert them to contract-demand contracts. This will, among other things, impact the AGD's ability to provide sufficient pipeline capacity for rendering the Back-Up Service.

Q. What is the current status of that proceeding?

A. On May 31, 2002, the FERC issued an order in this proceeding. In its order, the FERC concluded that pursuant to the federal Natural Gas Act, El Paso's current capacity allocation methodology was unjust and unreasonable and adversely affected the public interest. The order directed El Paso to modify its capacity allocation methodology to assure greater predictability for firm shippers on its system. The order further directed that full requirements contract shippers, such as the Company, be converted to service under contract-demand contracts effective November 1, 2002. The order did not set the quantitative level of contract-demand contracts for each full requirement shipper but allowed parties until August 1, 2002, to reach an agreement as to the capacity entitlements under the-new contract demand contracts.

Q. What happens if the parties cannot agree to the capacity entitlement level for converting full requirement shippers?

A. If the parties cannot reach agreement on the capacity entitlement level for converting full requirement shippers by August 1, the FERC has indicated that it will establish "appropriate" capacity entitlements for the converted contracts. Depending on how the conversion to contract demand is done, the result may be that AGD has insufficient capacity to meet its current requirements on the El Paso pipeline. In addition, it appears that the future demand growth that the Company has anticipated may be impaired by the capacity limitations on the El Paso pipeline.

Q. What is the affect of the recent FERC ruling on the AGD's gas rate filing?

A. The economic affect of the FERC El Paso order is not included in the rate application. At this point, the full effect of the FERC ruling is not fully known because the capacity entitlement levels have not yet been resolved. In addition, there is a clear possibility that the ruling may be appealed to the courts. However, it is clear that the mandated prohibition against full requirements shippers will have a significant affect on the Company's future business.

Q. Where are charges in the cost of gas and interstate pipeline transportation charges recorded?

A. In accordance with Commission current policy, the changes in purchase cost of gas and interstate pipeline transportation charges are reflected through the Company's Purchase Gas Adjustment filed with the Commission monthly.

Q. What changes is the Company proposing to the nomination and scheduling procedures in its T-1 Transportation tariff?

A. Since the Company last updated its T-1 Transportation Tariff, all interstate pipelines in the United States have adopted standards established by the Gas Industry Standard Board ("GISB") for the timely and efficient management of the movement of natural gas. To effectively coordinate and manage the transportation of gas for the Company's sales and transportation customer needs, the Company proposes to modify its nominating and scheduling procedures as set forth in Section 6.1 of Exhibit No. JAC-1. This modification would adopt the GISB standards for the timely nomination, scheduling, and confirmation of gas movement across the upstream pipelines and to the Company's distribution system. These standards have been set forth in AGD's upstream pipeline tariffs, which have been approved by the FERC. In the proposed changes for AGD's tariff, the Company would require that the transportation customer submit its nomination to the Company no later than one (1) hour prior to the upstream pipeline's nomination deadline for any nomination and scheduling cycle. This advance nomination and scheduling notice to the Company is necessary to provide for the Company's timely and efficient management of the both sales and transportation customer needs.

Q. Are there any other proposed changes to the operating procedures?

A. Yes. The Company is proposing to delete Section 6.1 (a), (b), and (c) in the current T-1 Transportation Tariff. Subpart (a) --which required prior day Receipt Point information -- is no longer necessary because the Company confirms nominations with the upstream pipelines. In addition, the scheduled quantities are available on the upstream pipelines' websites. Subpart (b) – which required prior day Delivery Point information-- is no longer needed because the Company has installed remote electronic telemetering on transportation meters. This electronic equipment allows the Company to continuously monitor customer usage through communication with remote computers located at the customer Delivery Point. Subpart (c) – which required that the customer provide daily expected consumption --is not necessary because there is a requirement that transportation customers submit daily nominations to the Company and that the upstream pipelines that reflect estimated requirements for the gas flow day for which the nominations are made. In addition, new Section 6.2 allows the Company with the right to request that the customer provide estimates of the daily, monthly and annual requirements.

Q. Is the Company proposing any other changes to the T-1 Transportation Tariff operation procedures?

A. No, it is not.

Q. What changes to the balancing provision of the tariff is the Company proposing?

A. The Company is proposing two basic changes to the imbalance provision of its transportation tariff. The first is to establish a monthly operating window or imbalance tolerance level. The second change is to establish a monthly imbalance charge to be applied on all quantities of imbalance gas outside of the monthly operating window.

Q. Please explain the monthly operating window that the Company proposes.

A. Imbalance occurs when there are differences between the quantity of gas scheduled and delivered by the customer to Receipt Points and the quantity of delivered by the Company to the Delivery Point. The Company recognizes that such imbalances will occur. The current T-1 Transportation Tariff permits a daily operating window, or imbalance, of +/- 25% of the scheduled transportation quantity or 1,370 therms, whichever is greater. The Company is now proposing, in addition to the daily imbalance tolerance level, to establish a monthly imbalance threshold of +/- 5% of the month's total scheduled transportation quantity or 10,000 therms, whichever is greater.

Q. What is the purpose of this proposed change?

A. The current tariff, while not explicit, **implies** a monthly operating window or imbalance of +/- 25% of the month's scheduled transportation quantity or 1,370 therms, whichever is greater. The upstream pipelines' tariff provisions impose a monthly imbalance tolerance level of +/- 5% on their customers. The Company believes that a monthly imbalance tolerance that is aligned with the upstream pipelines is more appropriate than the current 25% provide under the current tariff. Setting the monthly imbalance tolerance level at +/- 5%, along with the implementation of imbalance charges, will provide ample incentive for the Company's transportation customers to have quantities of gas delivered to the Company at Receipt Points that are reasonably equal to the quantity of gas being delivered by the Company to the transportation customer at the Delivery Point.

Q. You stated that the Company proposes to implement an imbalance charge. Would you please explain this charge and how it will be applied?

A. The Company proposes to implement an imbalance charge to provide for timely cash-out of imbalances that exist at the end of each month. See Section 7 of Exhibit JAC-1. The purpose of this charge is to provide a financial incentive for transportation customers to maintain any imbalance within the applicable operating window. The imbalance charge would be applied on a volumetric basis to the quantity of gas outside the monthly imbalance tolerance level. This imbalance charge would be in addition to charges payable under the transport tariff and the Customer's otherwise applicable sales schedule. The proposed imbalance charge would replace the Excess Gas charge in the current T-1 Transportation tariff.

Q. How would the proposed imbalance charge be calculated?

A. When the quantity scheduled for a transportation customer at the Receipt Point exceeds the customer's metered quantity at the Delivery Point by more than the monthly imbalance tolerance level, the excess gas imbalance will be retained by the Company. The customer's bill will be credited for the retained gas at a cost per therm equal to at the lower of: a) 50% of the Gas Cost component of the Base Tariff Rate contained in the customer's otherwise applicable sales schedule, as stated in the Statement of Rates, and adjusted for the PGA; or b) the lowest incremental cost of gas, including all upstream interstate pipeline transportation charges, purchased by the Company during the same month.

When the quantity that has been scheduled for a transportation customer at the Receipt Point is less than the customer's metered quantity at the Delivery Point by more than the imbalance tolerance level, the excess imbalance will be eliminated. The customer will be billed a gas cost per therm equal to the higher of: 1) 150% of the Gas Cost component of the Base Tariff Rate contained in the customer's otherwise applicable sales schedule, as stated in the Statement of Rates, and adjusted for the PGA; or 2) the highest incremental cost of gas, including all upstream interstate pipeline transportation charges, purchased by the Company during the same month.

Q. What would be the accounting treatment of collected imbalance charges?

A. Imbalance charges collected would be credited or debited to Account No. 191, the Deferred Gas Cost Account.

Q. Are there any other changes to the balancing provisions of the transportation tariff?

A. No.

Q. Would you please describe the miscellaneous administrative changes that the Company is proposing?

A. I have proposed seven additional revisions: (1) the key components of transportation service; (2) implementation of a minimum term for tariffed sales services; (3) requirement that customer provide certain information to the Company; (4) defined "quantity"; (5) clarified Company's liability; (6) clarified the requirement for telemetering facilities; and (7) clarified customer's responsibility for costs associated with the necessary telephone service for telemetering facilities.

Q. What is the proposed change relating to identifying the key components of the tariffed transportation service?

A. The Company proposes to add a new Section 2.1 that sets forth the components of the basic transportation service to be rendered under this schedule. These include the transportation of a Customer's gas delivered to Receipt Points across the Company's distribution system to the Customer at the Delivery Point.

Q. What is the proposed minimum term for the sales service tariff?

A. The current tariff requires that a customer receiving service under the T-1 Transportation Tariff do so for a minimum of twelve (12) months. After a customer has taken service for the minimum term, the customer may return to tariffed sales service. The Company's sales service tariff currently does not provide for a minimum term for a customer converting from transportation to sales service. The Company believes requiring a minimum sales service term of twelve (12) months when a customer converts from transportation to sales service is necessary to discourage customers from switching between the two services, based upon a more favorable commodity price. The proposed tariff language is set out in Section 2.3 of Exhibit JAC-1. Additionally, this commitment to sales service by the customer allows the Company to better provide for efficient planning and management of gas supply and pipeline capacity for meeting sale customers' requirements.

Q. Are there other miscellaneous changes being proposed to the T-1 Transportation Tariff?

A. Yes. The Company proposes to add new provisions under Sections 6.2, 6.3, and 6.4. Section 6.2 would require the customer to provide to the Company estimates of daily, monthly, and annual volumes of gas to be transported, upon request by the Company. This information may periodically be needed to assist the Company in planning for its system gas supply and operational requirements.

Section 6.3 defines quantities as used in Section 6.1 to dekatherms ("Dth") (one million Btus). This revision conforms the use of the term "quantity" under Section 6.1 to the definition that is used by the upstream pipelines for nominating and scheduling activities.

Section 6.3 clarifies that the Company will not be liable for failure to deliver gas to a customer at the Delivery Point, when the failure is caused by unavailability of the customer's gas supply or interruption of third party transportation services to the Receipt Point.

Q. Does the Company propose any further revisions to the transportation service tariff?

A. Yes, there is one final revision. The Company proposes to modify section 8.1 to require that telemetering facilities be installed on each meter through which a customer receives transportation service. Further, the Company proposes to revise this section to clarify that the customer is responsible for paying all costs associated with the telephone service that is necessary to provide communications between the telemetering facilities and the Company, as well as the cost of telemetering facilities.

Q. Does this conclude the proposed changes to the transportation tariff?

A. Yes, it does.

NEGOTIATED SALES PROGRAM

Q. What is the purpose of your testimony regarding the Negotiated Sales Program?

A. In November 1995, the Commission issued Decision No. 59399, which implemented the Negotiated Sales Program Tariff ("NSP"). A copy of that Decision is attached as Exhibit No. JAC-3. The Commission also ordered that NSP margins be reviewed in future base-rate and PGA cases. The Commission directed that the future disposition of NSP margins should be based on an assessment of the magnitude of NSP cost and benefits, and the extent to which the Company actually experiences exposure to a risk of loss. My testimony will address these issues.

Q. Would you please provide a brief description of the NSP?

A. The NSP is a service that allows the Company to participate in the competitive bidding process of its transportation customers who are seeking to purchase gas supplies for their own use in accordance with a transportation tariff. The NSP service allows the Company to offer to obtain the gas supply requirements for its transportation customers. The Company uses its upstream pipeline capacity to transport NSP volumes to the Receipt Points, except during periods when system requirements exceed the projected normal peak day throughput. Variable transportation costs billed to the Company by the upstream pipelines associated with transporting NSP volumes to the Receipt Point are directly charged to the NSP. The Company, in accordance with Decision No. 59399, credits the gas bank account for 50% of the sales margin, unless the NSP customer is a transportation customer who was a bundled sales customer anytime during the most recent three (3) year period. In that case, the Company credits the gas bank account for 100% of the sales margin.

Q. Is this the first review of the NSP?

A. No. In Commission Decision No. 59399, in addition to the review requirement in future base rate and PGA cases, the Commission mandated that the Company apply for a formal NSP review within two years of that Decision. On July 3, 1997, in compliance with that Commission Decision, the Company filed for the review to be undertaken. A copy of that application is attached to my testimony as Exhibit No. JAC-4.

Q. What did the Commission conclude from its review of the NSP in that docket?

A. In Decision No. 60423, issued on September 26, 1997, the Commission concluded that, after reviewing the Company's application and Staff's (September 10th) Memorandum, it was in the public interest to approve the filing. A copy of Decision No. 60423 and Staff's September 10, 1997, Memorandum are attached as Exhibit Nos. JAC-5 and JAC-6, respectively.

Q. Did the Decision change any procedures previously adopted in Decision 59399?

A. In Decision No. 60423, the Commission approved the Company's request to eliminate the restriction that, from November through March, the AGD not use its upstream capacity to transport NSP volumes to transportation customers.

Q. Were there any other modifications to the NSP as a result of Commission Decision No. 60423?

A. No, there were not.

Q. What have been benefits of the NSP?

A. The NSP provides two basic benefits. First, the NSP has provided transportation customers with a competitive alternative for the purchasing their gas requirements in the open market. That benefit is demonstrated by the fact that as of December 2001, sixteen (16) of the twenty (20) transportation customers, or 80%, purchased their gas requirements from the Company under the NSP. At the time of the initial review of the NSP in July 1997, the Company provided NSP sales service to only five transportation customers. This increase demonstrates that transportation customers have benefited from the NSP sales service.

Q. What is the second benefit?

A. The second benefit is that the NSP has lowered the cost of gas for AGD firm sales customers. During calendar years 2000 and 2001, the total margins realized from NSP sales were $590,801 and $1,497,684, respectively. Exhibit No. JAC-7 provides the monthly NSP sales for each of the calendar years 2000 and 2001. In accordance with Decision No. 59399, the margins for the years 2000 and 2001 would be $301,928 and $790,038.

Q. What risk does the Company take in rendering this service?

A. The Company is exposed to two basic risks. First, if NSP sales produce a loss, the Company absorbs 100% of those lost margins. In addition, the Company is at risk for collection of amounts billed to customers under the NSP. For calendar year 2001, NSP billings totaled $16.2 million. Because revenues and cost of NSP sales are below the line items, the Company bears the entire risk for any amounts that might be uncollectable.

Q. Has the Company actually experienced any losses associated with these risk?

A. Yes, unfortunately it has. One of the Company's transportation customers, Suntastic, who was also an NSP sales service customer, filed for bankruptcy in August 4, 2000. At the time the customer declared Chapter 11 bankruptcy, the Company had outstanding account receivables due from Suntastic of approximately $80,000. During the post bankruptcy period and prior to termination of service, the Company had outstanding account receivables due from Suntastic of approximately $206,000. This accounts receivable of approximately $286,000 remains uncollected today. The Company absorbed this loss, with no impact on customers.

Q. Do you believe that the NSP current level of sharing between the Company and its customers should be continued?

A. In light of the risks of loss that the Company absorbs, I think the current level of sharing is appropriate and fair.

BASE COST OF GAS

Q. What is the purpose of your testimony regarding cost of gas?

A. I am sponsoring testimony that supports the calculations used in developing the proforma base cost of gas used by the Company in this proceeding. Exhibit No. JAC-8 is the gas cost for the NAGD and Exhibit No. JAC-9 is the gas cost for the SCGD.

Q. How was the volume of natural gas to be purchased determined?

A. I began with the calendar month sales volume as set forth in Company witness, Mr. Harrison's, Exhibit No. JLH-3. The monthly volume represents the forecasted amount of gas that sales customers would consume during a normal month. This volume can be found on line 1 of Exhibit No. JAC-10 for the NAGD and line 15 for the SCGD.

I then adjusted the sales volume for the most recent loss and unaccounted for ("L&U") factor to arrive at the volume of gas to be delivered at the points of interconnection between the Company's distribution systems and the upstream pipeline suppliers ("City Gate"). I calculated the L&U adjustment by multiplying the sales volume by the L&U factor from the Company's most recent analysis. Copies of those analyses are attached as Exhibit No. JAC-11. The L&U factor for NAGD is 2.20% and SCGD is 1.02%. The sum of sales and L&U volumes provides the estimated City Gate requirements and can be found in Exhibit No. JAC-10 on line 3 for the NAGD and on line 17 for the SCGD.

Because two pipelines with different characteristics serve the AGD, the next step is to establish the volume of gas to be delivered to City Gates served by El Paso and Transwestern.

Q. How did you accomplish this?

A. For the purposes of this allocation, I used a 75%/25% split for El Paso and Transwestern respectively. I believe that this allocation is representative of the long-term utilization of these two pipelines for meeting the gas supply needs of the NAGD. Since the SCGD is served solely by El Paso, 100% of the City Gate deliveries were allocated to El Paso.

Q. Why do you make this allocation between El Paso and Transwestern served at the City Gates?

A. This allocation is made mainly to reflect the quantity of gas supplies to be transported on the upstream pipelines and to provide for a reasonable pipeline fuel adjustment. This fuel adjustment reflects the incremental quantity of gas to be purchased and delivered to the pipelines, as required by their respective tariffs, for fuel gas necessary to operate the El Paso and Transwestern compressors along their interstate pipeline systems. For El Paso the fuel rate is 3.47% and Transwestern is 4.75%.

Q. How are these adjustments made for the NAGD and SCGD?

A. For the NAGD, which is served by both El Paso and Transwestern, the amount of fuel gas required on each of the pipelines, is reflected in Exhibit No. JAC-8. Lines 9 and 13 reflect the amount of fuel gas to be purchased and delivered to El Paso and Transwestern. The sum of the City Gate and fuel purchases is the amount of gas to be delivered to the upstream pipelines and are those volumes on lines 10 and 14 of Exhibit No. JAC-8 for El Paso and Transwestern. For the SCGD, the El Paso fuel volumes are on line 7 of Exhibit No. JAC-9 and total purchases into the pipeline are on line 8.

Q. What is the next step?

A. The next step is to estimate the cost of the gas and that result is shown on line 34 of Exhibit No. JAC – 8 and line 26 of Exhibit No. JAC – 9. The result of this calculation is an annual commodity cost for the NAGD of $39,735,274 shown on line 34 of Exhibit No. JAC-8. The resulting SCGD annual commodity cost is $1,907,840, which is found on line 26 of Exhibit No. JAC-9.

Q. How did you calculate the projected annual purchased gas commodity cost?

A. I calculated the projected purchase gas commodity cost by multiplying the projected purchases by the net index monthly commodity cost per Dth.

Q. What was the next step in calculating AGD's cost of gas?

A. Next, I determined the estimated cost that would be incurred from the upstream pipelines for the transportation service in delivering gas to the City Gates.

Q. How did you derive at this upstream pipeline transportation cost?

A. First, I will describe the process that I followed for the NAGD. The NAGD receives service from both El Paso and Transwestern. Both pipeline contracts specify the payment of monthly demand charges based upon pipeline capacity entitlement, or the maximum daily quantity ("MDQ"), reserved for transporting gas on behalf of the Company. In the case of El Paso, the Company has been a full requirements customer. However, for billing purposes, a unit billing determinant was established as part of a long-term settlement with El Paso in 1996. The Company's El Paso transportation billing determinant is 37,611 dekatherms, which is allocated 34,544 dekatherms for NAGD and 3,067 dekatherms for SCGD. In the case of Transwestern, the Company has a contract MDQ of 25,000 dekatherms. Because Transwestern serves only the NAGD, this capacity is allocated solely to the NAGD.

To determine the projected NAGD upstream pipeline demand cost, I multiplied the MDQ by the current upstream pipeline tariff rates. For El Paso, the MDQ, applicable rate and resulting demand cost are shown on lines 37 through 39 of Exhibit No. JAC-8. For Transwestern, the MDQ, applicable rate and resulting demand cost are shown on lines 45 through 47. The estimated annual upstream pipeline costs are $3,237,960 for El

Paso and $2,585,113 for Transwestern.

For the SCGD, I followed the same process as I used for the NAGD except that El Paso is the only upstream pipeline serving City Gates in the SCGD. The derivation of the $287,484 of El Paso demand cost for SCGD are shown on lines 29 through 31 of Exhibit No. JAC-9.

Q. You testified earlier that the FERC had ordered that El Paso full requirement shippers be converted to contract-demand contracts. Does your gas cost forecast reflect changes for transportation charges after conversion to a contract-demand contract?

A. No, it does not.

Q. Please explain why not.

A. While the order states that full requirement shippers must convert to contract demand contracts by November 2002, it is the Company's belief that the FERC order is sufficiently flawed that it will be appealed, and that implementation may be delayed. Because of these uncertainties, I have not attempted to include any cost that might be associated with implementation of the FERC order in the forecasted gas cost.

Q. What was the next step for projecting upstream pipeline transportation service cost?

A. I then determined the upstream pipeline variable transportation cost. This cost is based on the volume of gas delivered to the City Gate by each pipeline.

To determine the projected NAGD upstream pipeline variable cost, I multiplied the City Gate purchase requirements by the current upstream pipeline tariff rates. For El Paso, variable transportation charges (line 41) were calculated by multiplying City Gate volumes on (line 8) by the variable transportation rate on (line 40 of Exhibit No. JAC-8). For Transwestern, variable transportation charges (line 49) are calculated by multiplying City Gate volumes on (line 12) by the variable transportation rate on (line 48 of Exhibit No. JAC-8). The estimated variable transportation charges resulting from these calculations are $218,373 for El Paso and $66,946 for Transwestern.

To determine the projected SCGD upstream pipeline variable cost, El Paso variable transportation charges (line 33) are calculated by multiplying the City Gate purchase requirements on (line 6) by the variable transportation rate on (line 32 of Exhibit No. JAC-9). The estimated annual variable transportation charges resulting from this calculation is $13,982.

Q. Are there any additional costs included in your projections?

A. Yes. As part of the long-term settlement with El Paso reached in 1996, customers of El Paso will receive a credit for a portion of revenues that El Paso receives from the resale of pipeline capacity that was deemed at risk during the settlement negotiations. To project risk-sharing credits, I assumed that the Company's future credits from El Paso would equal the average of actual risk-sharing credits received during the test year, calendar year 2001. The projected risk-sharing credits for the NAGD are on line 42 of Exhibit No. JAC-8 and reflect an annual credit of $475,596. The projected risk sharing credits for SCGD are on line 34 of Exhibit No. JAC-9 and reflect an annual credit of $21,864.

Q. Does this conclude the steps followed in determining the projected cost of gas purchases for the NAGD and SCGD?

A. Yes, it does.

Q. Would you please summarize purchase gas cost resulting from your calculations?

A. The NAGD is forecasted to require 10,626,427 dekatherms of gas to meet the forecast sales demand of its customers. The total cost, delivered to the City Gates, is $45,368,070 with $39,735,274 related to the cost for purchasing the commodity itself and $5,632,796 related to the cost of transportation services on the upstream pipelines.

The SCGD is forecasted to require 510,297 dekatherms of gas to meet the forecasted sales demand of its customers. The total cost, delivered to the City Gates, is $2,187,442 with $1,907,840 related to the cost of purchasing the commodity and $279,602 related to the cost of transportation services on El Paso.

Q. Does this conclude your testimony?

A. Yes, it does.

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TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
RATE SCHEDULE T-1

1. AVAILABILITY

This rate schedule is available to any qualifying Customer for transportation of natural gas by the Company from existing interconnects between the Company and upstream pipelines (herein called Receipt Point) to the Delivery Point(s) on the Company's system throughout its certificated Arizona gas service territory under the following conditions:

1.1 The Company has available capacity to render the requested service without construction of any additional facilities, except as provided by Section 8 hereof.

1.2 The Customer has demonstrated to the Company's satisfaction the assurance of natural gas supplies and third-party transportation agreements with quantities and for a term compatible with the service being requested from the Company.

1.3 The Customer and the Company have executed a Transportation Agreement, and the Customer is to be the End-User.

1.4 The Customer's gas to be transported is greater than 120,000 therms per year. A Customer receiving service from the Company at multiple locations may aggregate meters with annual consumption of no less than 50,000 therms to qualify for this service provided that all meter locations are served under a single entity.

2. SERVICES AVAILABLE

This schedule shall apply to gas transported by the Company for Customer pursuant to the executed service agreement.

2.1 The basic transportation service rendered under this schedule shall consist of:

(a) The receipt by the Company for the account of the Customer of the Customer's gas at the Receipt Point;

(b) The transportation of gas through the Company's gas system for the account of the Customer; and

(c) The delivery of gas after transportation by the Company for the account of the Customer at the Delivery Point(s).

2.2 Transportation: Service is firm and uninterrupted except for the following:

(a) curtailment in accordance with the Company's curtailment priority procedures;

(b) when the Company determines it has insufficient capacity on its system or from its upstream pipeline;

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
RATE SCHEDULE T-1
(Continued)

(c) Customer's gas supply to the Company is insufficient to meet its requirement.

2.3 Any Customer served under this schedule that requests service under a sales schedule is ineligible to return to transportation service for a period of not less than twelve (12) months.

3. RATES

3.1 A discount from the following rates may be offered at the sole discretion of the utility if such discount is in the best interest of the Company and its ratepayers. The maximum amount that the Customer shall pay the Company monthly will be the sum of the following charges:

Basic Customer Charge: The Basic Customer Charge is $95.00 per meter per month.

Volume Charge: An amount equal to the applicable unit transportation rate for each therm of Customer-secured gas metered and delivered to the Customer. The unit rates shall be as set forth in the currently effective Statement of Rates of this Arizona Gas Tariff. The volume charge will consist of the following:

(a) An amount equal to the applicable unit sales margin for each therm as set forth in the Customer's otherwise applicable sales tariff for each meter. This volume charge will cover the Company's Basic Cost of Service Rate as specified in the currently effective gas sales tariff but not including the Embedded Gas Cost specified therein. In no event will the minimum charge be less than that set forth in Item 4.1 below.

(b) An amount to reflect lost and unaccounted for gas as determined by the differential between the gas cost on a sales basis and gas cost on a purchase basis determined in the development of the currently effective Statement of Rates, Rate Rider No. RR-1 of this Arizona Gas Tariff. The Company at its sole option may allow lost and unaccounted for gas to be paid in kind.

(c) Any applicable imbalance charges as specified in Section 7 of this schedule.

(d) Any charges from upstream pipeline transporters or suppliers which have been incurred by the Company in excess of those specified in section (c) above and are deemed by the Company to be applicable to the transportation service rendered for the Customer under these rate schedules.

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
RATE SCHEDULE T-1
(Continued)

3.2 The charges specified for this rate schedule are subject to adjustment for the applicable proportionate part of any taxes, assessments or governmental impositions, which are assessed and are not otherwise included in the Company's margin rates.

4. MINIMUM CHARGE

4.1 The minimum charge will be the Basic Customer Charge plus $0.005 per therm.

5. ADMINISTRATIVE PROCEDURES

5.1 Processing Requests for Transportation Service. Requests for transportation hereunder shall be made by, and shall be deemed to be complete upon, the Customer providing the following information to the Company.

(a) Gas Quantities - The Maximum Daily Quantity applicable to the receipt point and the Maximum Daily Quantity applicable to each delivery point, and estimated total quantities to be received and transported monthly over the delivery period should be stated individually in therms for each receipt point.

(b) Delivery Point(s) - Point(s) of delivery by the Company to the Customer.

(c) Term of Service -
(i) Date of service requested to commence;
(ii) Date service requested to terminate; if known, and
(iii) Minimum term for transportation service shall be twelve (12) months.

(d) Performance - A statement from the Customer certifying that the Customer has or will have title to the gas to be delivered to the Company for transportation and has entered into or will enter into those arrangements necessary to assure all upstream transportation will be in place prior to the commencement of service under a Transportation Agreement. The Customer's Agent, if any, must be named.

Upon receipt of all of the information specified above, the Company shall prepare and tender to the Customer for execution a Transportation Agreement. If the customer fails to execute the Transportation Agreement within thirty (30) days of the date tendered, the Customer's request shall be deemed null and void.

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
RATE SCHEDULE T-1
(Continued)

6. OPERATING PROCEDURES

6.1 Nominating and Scheduling of Gas Receipts and Deliveries. GISB guidelines will be followed regarding nominating, confirming and scheduling gas receipts and deliveries as they may be revised by the FERC from time to time. The Customer shall be responsible for contacting the upstream pipelines to arrange for the nominating and scheduling of receipts and deliveries hereunder, provided, however, that the Customer may designate one (1) other party to serve as his agent for such purpose.

The Customer or Customer's Agent shall be responsible for submitting nominations to the Company via facsimile or other Company-approved method no later than one (1) hour prior to the upstream pipeline's nomination deadlines set forth in the upstream pipeline's FERC approved tariff. The Company will confirm whether it has sufficient operational capacity to deliver all or a portion of the Customer's gas.

6.2 Operating Information and Estimates. Upon request of the Company, the Customer shall from time to time submit its best estimates of the daily, monthly and annual volumes of gas to be transported, including peak day requirements, together with such other operating data as the Company may require in order to schedule its operations.

6.3 Quantities. All quantities referred to in Section 6 shall be provided as dekatherms ("Dth's") (one million British Thermal Units).

6.4 Deliverability. The Company shall not be liable for its failure to deliver gas when such failure is due to unavailability of gas supply or interruption of third party transportation services.

6.5 Other Operating Procedures. The Company may require additional information or enforce other operating procedures as deemed necessary in the Company's sole judgment, in order to coordinate gas volumes and the movement of gas through the upstream pipeline system to the Company's Arizona Gas Service Territory. These additional operating procedures may be enforced upon verbal notice to each Customer or the Customer's Agent with twenty-four hour notice of implementation.

6.6 Balancing. Balancing of thermally equivalent volumes of gas received and delivered shall be achieved as nearly as feasible on a daily basis, taking into account the Customer's right, subject to prior Company approval, to vary receipts and deliveries across the Company Distribution System. Customer daily imbalances are defined as the difference between the Customer's daily metered quantity and the sum of the Customer's daily scheduled transportation quantity plus any Company-approved daily imbalance adjustment quantity. Customer monthly imbalances are defined as the difference between the Customer's total monthly metered quantities and the

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
RATE SCHEDULE T-1
(Continued)

Customer's total scheduled transportation quantity. Customers are provided a monthly operating window under which the Customer's cumulative imbalances must be within plus or minus 5 percent (+/-5%) of the month's total of daily scheduled transportation quantities, plus any Company-approved imbalance adjustment quantity, or 10,000 therms, whichever is greater. Furthermore, Customers are provided a daily operating window under which the Customer's daily delivery imbalance must be within plus or minus twenty-five percent (+/-25%) of the daily scheduled transportation quantity or 1,370 therms, whichever is greater. Imbalances established in excess of the applicable monthly operating windows will be subject to imbalance charges as specified in Section 7 of this schedule. If in the Company's sole good faith judgment operating conditions permit, the Company will increase the daily operating window with such increase operable on a day-to-day basis. Any imbalance (plus or minus) carried forward shall be considered first through the meter during the next daily or monthly period, as applicable.

6.7 Adjustments. Periodically, volume adjustments may be made by the upstream pipelines or the Customer's Agent. Therefore, actual daily volumes invoiced will be compared with daily nominated volumes. Should adjustments to the nominated volumes become necessary, such adjustments will be applied to the nomination for the month in which the volumes were delivered to the Customer for the purposes of determining the applicability of the provisions of this rate schedule.

6.8 Customer Default: The Company shall not be required to perform or continue service on behalf of any Customer that fails to comply with the terms contained in this schedule and the terms of the Customer's Transportation Service Agreement with the Company. The Company shall have the right to waive any one or more specific defaults by any Customer under any provision of this schedule or the service agreement, provided, however, that no such waiver shall operate or be construed as a waiver of any other existing or future default or defaults, whether of a like or different character.

6.9 Operational Curtailment. The Company reserves the right to impose, at any time, any reasonable operating conditions upon the transportation of the Customer's gas which the Company, in its sole good faith judgment, deems necessary to maintain with safe and efficient operation of its distribution system, or to make the operating terms and conditions of service hereunder compatible with those of its upstream pipelines. Under such circumstances, the following conditions shall apply:

(a) Any Customer that does not comply with a notice of operational curtailment shall be subject to, in addition to any otherwise applicable charges, a penalty of $10.00 per Dth for all unauthorized quantities during the curtailment period.

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
RATE SCHEDULE T-1
(Continued)

(b) The Company shall endeavor to provide notice of such operational curtailment 48 hours prior to the commencement of the delivery of gas.

(c) Notwithstanding condition (b), the Company may impose an operational curtailment on the current gas day. In the event an operational curtailment is imposed on the current gas day, a minimum one-hour grace period will be allowed before penalties begin to apply.

7. IMBALANCE CHARGE - PAYMENT FOR EXCESS IMBALANCE QUANTITIES

7.1 Customers will be assessed imbalance charges if an imbalance exists in excess of the applicable monthly operating windows set forth in Section 6.6 hereof. The portion of any imbalance quantity established by a Customer in excess of the applicable monthly operating window is defined as an excess imbalance quantity. In addition to the charges payable under this schedule and the Customer's otherwise applicable sales schedule, any month excess quantity shall be billed as follows:

(a) Positive Excess Imbalance

When the Customer's scheduled transportation quantity exceeds the Customer's metered quantity by more than the applicable monthly operating window, the excess imbalance shall be retained by the Company and the excess imbalance eliminated after the Customer's bill is credited at the lower of the following two gas costs for each therm retained:

(i) Fifty percent (50%) of the Gas Cost component of the Base Tariff Rate contained in the Customer's otherwise applicable sales schedule as stated in the Statement of Rates, adjusted for the PGA; or

(ii) The lowest incremental cost of gas, including all upstream interstate transportation charges, purchased by the Company during the same month.

(b) Negative Excess Imbalance

When the sum of the Customer's scheduled transportation quantity is less than metered quantity by more than the applicable monthly operating window, the excess imbalance shall be eliminated after the Customer is billed the higher of the following two gas costs for each therm of the excess imbalance in addition to the customer's applicable transportation volume charge:

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
RATE SCHEDULE T-1
(Continued)

(i) One hundred-fifty percent (150%) of the Gas Cost component of the Base Tariff Rate contained in the Customer's otherwise applicable sales schedule as stated in the Statement of Rates, adjusted for the PGA; or

(ii) The highest incremental cost of gas, including all upstream interstate transportation charges, purchased by the Company during the same month.

7.2 Notwithstanding the provisions outlined in Section 7.1 above, should the Customer cease to utilize transportation service under this rate schedule, the Company may allow, in its sole good faith judgment, any remaining imbalance to be cleared as follows:

(a) When receipt by the Company exceeds delivery to the Customer, the Company shall credit the Customer for the excess quantity at a price equal to the lowest delivered system supply price paid by the Company during the prior month for gas delivered to the Company within its Arizona Gas Service Area.

(b) When delivery to the Customer exceeds receipt by the Company, the Customer shall pay for the excess quantity at the otherwise applicable gas sales tariff rate.

7.3 Under no circumstances shall Section 7.1 above be considered as giving the Customer any right to take excess quantity gas, other than as provided by Section 6.3 hereof, nor shall Section 7.1 or payment thereunder be considered as a substitute for any other remedy available to the Company against the offending Customer for failure to respect its obligation to stay within its authorized quantities.

8. FACILITY ADDITIONS

8.1 Any facilities which must be installed by the Company to serve the Customer will be constructed in accordance with the Rules of Service as approved from time to time by the Arizona Corporation Commission. Telemetering facilities on each meter will be installed at Customer's expense. Customers requiring telemetering facilities shall provide, at the Customer's expense, a dedicated telephone line for the Company's use in communicating with the telemetering facilities and will pay all and any costs associated with that phone line. Further, any existing special surcharges or minimum bill provisions designed to recover the cost of facilities for any Customer shall remain in effect and may serve to increase maximum allowable transportation rate levels pursuant to this tariff schedule.

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
RATE SCHEDULE T-1
(Continued)

9. THIRD PARTY CHARGES

9.1 The Customer shall reimburse the Company for any charges rendered or billed to the Company by its upstream pipelines and by any other upstream transporter and gas gatherers, either before or after termination of the Transportation Agreement, which the Company, in its sole good faith judgment, determines have been incurred because of the transportation of Customer's gas hereunder and should, therefore, appropriately be borne by the Customer. Such charges, whether levied in dollars or gas, may include, but shall not be limited to, standby charges or reservation fees, prepayments, applicable taxes, applicable fuel reimbursement, shrinkage, lost and unaccounted for volumes, G.R.I. surcharges, penalty charges, and filing fees.

The Customer will reimburse the Company for all such charges incurred by the Company as rendered, irrespective of the actual quantities of natural gas delivered to the Customer.

10. CONDITIONS FOR CONVERTING TO T-1 SERVICE

Any qualified Customer converting from gas sales service to service under this rate schedule is subject to the following conditions and requirements:

10.1 T-1 service will commence at the beginning of the first calendar month following the end of five (5) days after receipt of the customer service change request.

10.2 Customer will be billed or credited the Customer's pro rata share of the balance in the Company's Purchase Gas Adjustment ("PGA") bank accumulated while served under the Company's sales tariffs, calculated as follows:

(a) Starting from the later of the month of initiation of gas sales service by the Customer, or the date of initiation of the current PGA bank, through the Customer's last month of sales service, the Customer's actual therm usage will be multiplied, on a month-by-month basis, by the difference between the Company's actual commodity cost per therm and the Gas Cost component of the Base Tariff Sales Service Rate adjusted for any PGA and PGA Surcharge that may be in effect from time-to-time;

(b) The sum of these monthly calculated values equals the Customer's charge or credit due for conversion to service under this rate schedule;

(c) Customer charge or credit will be paid in twelve (12) equal monthly payments, including interest equal to the carrying charge rate applicable to the PGA bank at the time of conversion to service under this rate schedule.

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
RATE SCHEDULE T-1
(Continued)

10.3 If a Customer converts back to a rate schedule for gas sales service which the PGA cost surcharge existing at the time of the switch to T-1 service is still in effect, such Surcharge will not be applicable to the Customer's billed usage for the period it remains in effect. However, any future Gas Cost Surcharge that may be put into effect will be applicable to the Customer's billed usage.

11. CONDITIONS

11.1 Subject in all respects to all applicable laws, and to the rules and regulations of the Arizona Corporation Commission from time to time in effect.

11.2 Transportation of Customer owned natural gas hereunder shall be limited to natural gas of equal or higher quality than natural gas currently available from the Company's supplier(s). All gas delivered by the Company to the Customer shall be deemed to be the same quality as that gas received by the Company for transportation.

11.3 With respect to the Company's capacity to deliver gas at any particular time, the curtailment priority of any Customer served under this schedule shall be the same as the curtailment priority established for other Customers served pursuant to the Company's rate schedule, which would otherwise be applicable to such Customer.

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
William L. Massey, Linda Breathitt,
And Nora Mead Brownell.

El Paso Natural Gas Co.	Docket No. RP00-336-002
Aera Energy, LLC, et al., Complainants v. El Paso Natural Gas Co., Respondent	Docket No. RP01-484-000
Texas, New Mexico and Arizona Shippers, Complainants v. El Paso Natural Gas Co., Respondent	Docket No. RP01-486-000
KN Marketing, L.P., Complainant v. El Paso Natural Gas Co., Respondent	Docket No. RP00-139-000

ORDER ON CAPACITY ALLOCATION
AND COMPLAINTS

(Issued May 31, 2002)

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APPENDIX B: Summary of Comments Submitted Regarding the April 16th, 2002 Public Conference

APPENDIX C: Summary of Affidavits Submitted by Contract Demand Customers

ORDER ON CAPACITY ALLOCATION AND COMPLAINTS

This order resolves issues in four non-consolidated proceedings, all of which concern capacity allocation on El Paso Natural Gas Company's (El Paso) system. As discussed below, the Commission finds pursuant to section 5 of the Natural Gas Act (NGA), that the application of El Paso's current capacity allocation methodology is unjust and unreasonable and adversely affects the public interest because parties with firm transportation contracts are not receiving the firm service for which they are paying. Therefore, this order directs El Paso to modify its capacity allocation methodology to assure greater predictability for firm shippers.

This order directs that full requirements (FR) contract shippers on El Paso will be converted to service under contract demand (CD) contracts, effective November 1, 2002. The order provides the parties with a short period of time to reach an agreement as to the FR customers' entitlements under their new CD contracts. If the parties do not agree as to the appropriate CD entitlements, the Commission will determine the appropriate CD levels. Small shippers will be permitted to retain full requirements service under El Paso's Rate Schedule FT-2 as long as their requirements remain less than 10,000 Dth/d. Additionally, as explained below, the Commission will require an assignment of primary receipt rights to shippers, and allow El Paso to increase the number of pooling points on its system from 6 to 8. The Commission also directs El Paso to revise its tariff to establish flexible delivery/receipt points at the California border. With respect to allocable capacity, the Commission will conditionally require El Paso to accept turnbacks of existing CD entitlements and expects El Paso to follow through in its offer to seek authorization and place into service its Line 2000 PowerUp Project. This order also directs El Paso to pay demand charge credits if it is unable to schedule firm service for reasons other than force majeure.

Together, these capacity allocation measures appropriately balance the interests of all the parties to this proceeding and are in the public interest because they will resolve the current uncertainty on El Paso's system and assure that firm shippers receive the firm service to which they are entitled, consistent with Part 284 of the Commission's regulations[1] and section 5 of the Natural Gas Act (NGA). In addition, the capacity allocations will establish the proper market incentives for expansion of the infrastructure.

I. Background

[1] 18 C.F.R. Part 284 (2001).

El Paso operates a gas pipeline system that can deliver gas from three production basins, i.e., San Juan, Permian, and Anadarko, to various delivery points on its system. In recent years, gas supplies from the San Juan Basin have been less expensive than gas from the Permian and Anadarko Basins, making the San Juan Basin the preferred production area of El Paso's customers.[2] While the Commission has held that where it is operationally feasible, a pipeline should assign customers specific capacity rights at receipt and delivery points,[3] El Paso does not do so. Instead, in most instances, El Paso's contracts for firm transportation service provide for system-wide access to receipt and delivery points, and customers have no specified rights to pipeline capacity. If shippers' nominations exceed the physical capacity of a specific receipt point, El Paso's tariff provides for pro-rata allocation based on the nominated amount.

The issue of system-wide delivery points was addressed by the Commission in Amoco Energy Trading Co. v. El Paso Natural Gas Co. (Topock).[4] In Topock, the Commission found that El Paso's pro rata allocation of capacity at Topock and other delivery points was unjust and unreasonable because firm shippers were not receiving reliable firm service. The Commission ordered El Paso to assign specific delivery point rights. The Commission further ordered El Paso to file a proposal to allocate receipt point capacity.

El Paso has historically served its firm customers under two types of contracts: CD and FR contracts. CD contracts provide specific delivery rights up to a specified quantity limitations at delivery points designated in the contract. FR contracts provide that El Paso must deliver and the customer must take from El Paso, the customer's full natural gas requirements each day. In 1990, El Paso implemented contract conversions from bundled sales service to transportation service through a Global Settlement with its customers.[5] The Global Settlement specifically provided for the continuation of FR

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[2]For example, the "Monthly Index" in the "Monthly Contract Index" reported for El Paso in the January 2002 Gas Daily Price Guide is $2.56/MMBTU for the Permian Basin and $2.48/MMBtu for the San Juan Basin. The bid week low-high is reported as $2.42-75 in the Permian Basin and $2.30-63 in the San Juan Basin.

[3]Transcontinental Gas Pipe Line Co., 76 FERC ¶ 61,021 at 61,063 (1996).

[4]93 FERC ¶ 61,060 (2000), order on clarification, 93 FERC ¶ 61,222 (2000), order on reh'g, 94 FERC ¶ 61,225 (2001).

[5]54 FERC ¶ 61,316, reh'g, 56 FERC ¶ 62,290 (1991).

service.[6] The CD contracts are held mainly by customers that serve the California markets. The FR contracts are held mainly by customers east of California (EOC). Full requirements customers are not limited to a specific contract demand quantity. Like the CD contracts, FR contracts have system-wide primary receipt point rights. This means that shippers are free to nominate from any basin or pool to satisfy their needs. Under the General Terms and Conditions of El Paso's tariff,[7] if El Paso has insufficient capacity to serve all transportation requests at a nominated receipt pool, the firm shippers are subject to pro-rata cuts based upon available capacity.

On March 15, 1996, El Paso filed another settlement (1996 Settlement) that set the current rates, and terms and conditions of service that apply on its system for a ten-year period, i.e., until January 1, 2006. The 1996 Settlement also imposes a ten-year moratorium, under which El Paso cannot file for a general rate change and the parties may not file a section 5 complaint challenging the Settlement rates. The Commission approved the 1996 Settlement.[8] At the time the 1996 Settlement was filed, there was substantial excess capacity on El Paso's system, as the California LDC customers turned back capacity rights in accordance with their contracts. This capacity turn-back threatened to increase the rates of the remaining El Paso customers.[9] The 1996 Settlement resolved the capacity turnback problem through an agreed-upon sharing of the risk of unsubscribed or undersubscribed capacity.

Under the terms of the 1996 Settlement, the CD customers pay a reservation charge pursuant to Rate Schedule FT-1 based on their contract entitlements. The Rate Schedule FT-1 FR customers pay reservation fees based on their billing determinants as established in the 1996 Settlement.[10] The reservation fees have remained unchanged while many of the FR shippers' demands have grown; the result is that the FR shippers

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[6] Section 3.6 of the Settlement provides in part: It is further stipulated and agreed that El Paso's east-of-California customers may convert their existing firm sales entitlements to either firm full requirements or firm contract demand service...or a combination of both.

[7] GT&C, Section 4.2.

[8] 79 FERC ¶ 61,028, reh'g denied, 80 FERC ¶ 61,084 (1997).

[9] See 89 FERC ¶ 61,164 at 61,489 (1999).

[10] Additionally, under Rate Schedule FT-2, El Paso serves various small EOC customers on a volumetric rate basis. Unless otherwise noted, reference to FR shippers in this order will refer to Rate Schedule FT-1 FR shippers.

pay only a small usage charge for their incremental takes above the Settlement billing determinants.

Circumstances on El Paso's system have changed dramatically since 1996, when excess capacity and capacity turn-back were problems on the system. The turned-back capacity has been resold, and the FR shippers' load has grown. There is now insufficient capacity to meet the demands of all firm shippers. As explained above, gas from the San Juan Basin is preferred by El Paso's shippers because it is less expensive than gas from the Permian or Anadarko Basins. The preference for the San Juan Basin gas, together with the growth in demand from the FR shippers and the lack of incentives to expand the infrastructure have caused all firm shippers to experience frequent pro-rata nomination reductions. Many FR shippers have, nevertheless, received service in quantities that exceed their 1996 Settlement billing determinant levels. This has resulted in tension between the FR and CD customers which underlies each of the proceedings addressed in this order.

II. Procedural History

The four proceedings addressed in this order grow out of the increasing unreliability of firm service on El Paso. The first of the three complaints addressed in this order was filed by KN Marketing on December 16, 1999, alleging that El Paso's allocation of firm mainline capacity on the east end of its system, i.e. the San Juan Basin to Texas, is unjust and unreasonable because El Paso sells firm capacity in excess of the available capacity. In its order in Amoco Energy Trading Company v. El Paso Natural Gas Co. (Topock),[11] the Commission held the issues raised by the KN complaint in abeyance pending examination of system-wide capacity allocation issues in El Paso's Order No. 637 proceeding. The Commission directed El Paso to file a systemwide capacity allocation proposal in its Order No. 637 proceeding, and provided for parties to submit comments on El Paso's proposal. On March 28, 2001, El Paso filed its system-wide capacity allocation proposal in the Order No. 637 proceeding (i.e., Docket No. RP00-336-002). El Paso proposes to allocate capacity to the FR shippers based on their 1996 Settlement billing determinants. Commenters on El Paso's proposal recommended alternative methods for allocating capacity, including a proposal by Salt River Project to use FR shippers' historical non-coincidental peak demands.

After El Paso made its capacity allocation filing, two additional complaints were filed, one by a group of El Paso's CD shippers and one by a group of El Paso's FR

[11] 93 FERC ¶ 61,060 (2000), order on clarification, 93 FERC ¶ 61,222 (2000), order on reh'g, 94 FERC ¶ 61,225 (2001).

shippers, concerning capacity allocation issues. On July 13, 2001, a group of El Paso's California CD customers filed a complaint in Joint Complainants[12] v. El Paso, Docket No. RP01-484-000, alleging that El Paso had oversold its firm capacity and that this, combined with the growth of the demand of the FR customers, has resulted in unjust and unreasonable services on the El Paso system. On July 17, 2001, a group of El Paso's FR customers filed a complaint in Texas, New Mexico, and Arizona Shippers[13] v. El Paso, Docket No. RP01-486-000, alleging that El Paso violated the NGA by failing to maintain its facilities in a manner that will allow it to provide firm service up to certificated levels.

Details of El Paso's proposal and the alternative capacity allocation proposals before the Commission are set forth in Appendix A. The timely motions to intervene in the four proceedings are granted pursuant to Rule 214 of the Commission's Rules of Practice and Procedure. 18 C.F.R. § 385.214 (2001).

III. Discussion

All of the captioned proceedings involve the issue of whether El Paso's application of the capacity allocation mechanism in section 4.2 of its General Terms and Conditions (GT&C) is just and reasonable. Underlying issues are the extent to which unrestricted growth under the FR contracts has produced unjust and unreasonable results vis-a-vis El Paso's other firm services,[14] whether FR contracts should be converted to CD contracts

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[12]Joint Complainants are Aera Energy LLC (Aera), Amoco Production Company (Amoco), BP Energy Company (BP), Burlington Resources Oil & Gas Company LP (Burlington), Conoco, Inc (Conoco), Coral Energy Resources LP (Coral Energy), ONEOK Energy Marketing & Trading Company, L.P. (Oneok), Pacific Gas and Electric Company (PG&E), Panda Gila River L.P. (Panda Gila), the Public Utilities Commission of the State of California (CPUC), Southern California Edison Company (SoCalEdison), and Texaco Natural Gas Inc. (Texaco).

[13]These shippers are Apache Nitrogen Products, Inc. (Apache), Arizona Electric Power Cooperative, Inc. (AEP), Arizona Gas Division of Citizens Communication Company (Citizens Communication), BHP Cooper, Inc. (BHP), El Paso Electric Company (El Paso Electric), El Paso Municipal Customer Group (EPMCG), Phelps Dodge Corporation (Phelps Dodge), New Mexico PSC, Salt River Project (Salt River), and Southern Union Gas Company (Southern Union).

[14]El Paso's design day delivery capacity is approximately 5,400,000 Dth/d. CD entitlements total 4,316,000 Dth/d. Current CD entitlements and FR demands exceed the capacity of the El Paso system. At the time of the 1996 Settlement, FR billing

(continued...)

and, if so, at what CD entitlement levels. In addition, the parties have raised issues concerning whether El Paso is obligated to expand its system to meet the needs of its firm shippers and whether El Paso should be required to provide demand charge credits to firm shippers that pay demand charges for volumes El Paso is unable to transport. The Commission will address these issues below, and then will apply its conclusions on each issue to the individual proceedings.

For the reasons discussed below, the Commission concludes that as a result of a lack of specified receipt point entitlements in El Paso's tariff, the frequent pro rata allocation of firm capacity on El Paso's system,[15] and the lack of proper price signals for the expansion of the infrastructure, El Paso's current capacity allocations are no longer just and reasonable nor in the public interest. Therefore, the Commission must act under section 5 of the NGA to establish just and reasonable firm service entitlements that are in the public interest. The Commission finds that the rapid and unrestricted growth in demand under the FR contracts has contributed to the current allocation problems on the system, and that continued unlimited growth in demand under these FR contracts is not just and reasonable and is not in the public interest. Therefore, the Commission finds that the Rate Schedule FT-1 FR contracts should be converted to CD contracts, effective November 1, 2002. Rate Schedule FT-2 service should be capped at a demand level of 10,000 Dth/d. All firm shippers must be assigned specific receipt and delivery point rights under their contracts.[16] Conversion of FR contracts to CD contracts, coupled with the assignment of specific point rights, will restore certainty to firm service, assure that

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[14](...continued) determinants were 788,039 Dth/d. The FR coincident peak demand for December 12, 2001 was 1,122,000 Dth/d. The FR non-coincident peak demand for 1995 was 1,092,181 Dth/d while in 2001, the total FR non-coincident peak demand was 2,167,107 Dth/d. In addition, while demands on El Paso's system historically peaked during the winter heating season months, El Paso's customers have increased their nominations during historical non-peak periods, primarily to serve electric generation demands.

[15]The pro rata allocations of capacity made by El Paso based on the customers' nominations result in cuts to the amounts nominated by the customers and the failure to schedule service for the full nominated volumes. In the case of the CD customers, demand charges have already been paid for this capacity, and the customers therefore do not receive the service they are paying for.

[16]As noted above, in Topock the Commission required El Paso to establish specific delivery point rights under CD service. 93 FERC ¶ 61,222, reh'g, 94 FERC ¶ 61,225 (2001).

firm shippers receive the service they are paying for, and establish the proper price signals for expansion of capacity.

The appropriate level of CD entitlements therefore must be determined for each FR shipper. The Commission discussed several methods of establishing CD entitlements for the FR shippers at its March 13, 2002 meeting, and directed that a public conference be held to discuss the various methodologies, including the use of system peak day demands. At the public conference held on April 16, 2002 and in the written comments[17] filed on the proposal to use the system peak to establish CD levels, the FR shippers expressed concern that they be provided sufficient capacity to meet their summer and winter season demands. As explained more fully below, the Commission will afford the parties an opportunity to establish entitlements under the new CD contracts to reflect seasonal usage. After determining the appropriate CD entitlement for each customer, El Paso shall initiate a capacity rationalization process to make additional capacity available to the converting customers by providing an opportunity for shippers to turnback unwanted capacity and for converting shippers to request and purchase additional capacity. In this process, all shippers will have an opportunity to establish specific receipt point rights. If the parties are unable to reach an agreement on appropriate CD entitlements for the FR shippers, the Commission will determine the appropriate CD entitlement for the FR shippers.

A. El Paso's Application of Capacity Allocation Procedures Is No Longer Just and Reasonable Nor in the Public Interest

As is explained in more detail below, the Commission finds that El Paso's capacity allocation methodology, as it operates currently, is no longer just and reasonable because it results in regular reductions in firm service. As a consequence, CD shippers have sustained substantial harm.

There is no disagreement among the parties that firm shippers on El Paso have been subject to, on a regular and continuing basis, pro rata allocations of their daily nominations of firm capacity. At the April 16, 2002 public conference, El Paso admitted that it no longer had sufficient capacity to meet the demands of its customers.[18] The CD customers assert that because of the service reductions that result from these allocations, they cannot use the firm capacity that they have under contract and pay for, and that they

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[17]The comments of the parties filed in connection with the April 16, 2002 public conference are summarized in Appendix B.

[18]Transcript of Public Conference, April 16, 2002 (Tr.) at 13 and 18.

and the downstream markets they serve are financially harmed on a routine basis. In the complaint proceeding in Docket No. RP01-484-000, Joint Complainants submitted affidavits, as discussed in Appendix C, asserting that nomination scheduling cuts on El Paso have cost them millions of dollars in stranded demand costs.[19] CD shippers filed updated affidavits after the April 16 Public Conference. BP Energy, for example, in an affidavit by Russell Williamson, states that its cycle four cuts[20] were 40,063,202 MMBtu from January 1999 through December 31, 2001, resulting in stranded demand charges of $10,132,998.

The CD shippers point out that if APS/Pinnacle is permitted to increase deliveries to the new Redhawk plant in the Fall of 2002, APS/Pinnacle demands would increase by over 600 percent over its billing determinants and cause further service reductions to CD shippers. Further, the EOC growth in demand is projected to continue. The Arizona Corporation Commission noted that new electric generation is under construction in Arizona to meet the extraordinary growth in Arizona's need for natural gas; nearly 4,000 additional megawatts in electric generation capacity is scheduled to be completed within a year, and another 4,000 megawatts of generation capacity is approved or under construction for completion by the end of 2003.[21] Most, if not all, of this new generation capacity is projected to be fueled with natural gas.

The TNMA FR shippers agree that there are serious allocation problems on El Paso, and state that the system is in "full crisis"[22] with daily reductions in firm service as standard operating procedure. El Paso does not dispute the assertion that significant pro rata allocations in firm service nominations are taking place on a routine basis. El Paso states that in making these pro rata allocations, it has acted consistently with its tariff, the Settlements and customers' contracts. El Paso agrees with Joint Complainants that if it is

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[19]Stranded demand costs refer to dollars spent by the CD customers in demand charges for capacity that El Paso does not make available to them due to pro rata allocations.

[20]Cycle four is the last nomination cycle for the gas day. Cuts to cycle four nominations, therefore, are volumes that the shipper will not receive, for there are no subsequent opportunities that gas day to nominate at a different receipt point or from a different pipeline.

[21]Tr. at 48.

[22]Protest and Comments of Texas, New Mexico and Arizona Shippers, Docket No. RP01-484-000 filed August 2, 2001 at p. 9.

required in the future to serve unlimited demands of its FR customers, its current inability to provide firm service to those shippers paying for that firm service will be exacerbated.

APS/Pinnacle assert that a solution that caps FR service is discriminatory in its treatment of one class of customers and is therefore unreasonable. The Commission disagrees that the solution is unreasonable. The Commission is convinced that further increases under full requirements contracts will further degrade the quality of CD service and cause corresponding, equivalent decreases in service to CD shippers. Increases in demand of the magnitude required for the APS/Pinnacle Redhawk Plant will significantly degrade CD service and result in further harm. The Commission will not allow service to one group of firm customers to cause sustained financial harm to another group of firm customers.

The Commission finds, based on the representations of all of the parties in this proceeding, that El Paso does not have sufficient firm capacity to meet growing demand for firm service on its system, and firm service has been curtailed through pro rata allocations of service nominations on a routine basis.[23] Capacity allocation procedures that result in regular cuts in firm service are not just and reasonable. Pro rata allocation is an appropriate way to deal with emergency circumstances, but it cannot be a regular part of the daily scheduling process. For El Paso's capacity allocation methodology to be just and reasonable, a firm shipper must be able to reliably schedule its firm contractual entitlements without service reductions except for force majeure.[24]

As a consequence of demand growth and pro rata allocations on El Paso, the firm CD shippers have been unable to use the full amounts of their firm contract entitlements. Effectively, these customers pay demand charges for capacity they are unable to use. Section 284.7 of the Commission's regulations provides that firm service is service that is not subject to a prior claim by another customer.[25] It is inconsistent with this regulation for firm shippers to be charged for firm service and have service reduced through pro rata allocations on a non-emergency basis so that the pipeline can provide service to another shipper. A shipper contracting for firm service, as compared to interruptible, pays the pipeline a charge to reserve capacity on the pipeline in addition to the volumetric charge for actually transporting the gas. If the reservation portion of the firm transportation rate

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[23]See El Paso Data Response, filed August 23, 2001. Response No. 4 shows that El Paso made in excess of 10,000 pro rata allocations of service nominations between August 2000 and July 2001.

[24]Topock, 93 FERC ¶ 61,060 at 61,161.

[25]18 C.F.R. § 284.7 (2001).

does not in fact reserve capacity on the pipeline, that charge must be unjust and unreasonable because the shipper is paying for a service that it cannot receive.

In their post-technical conference comments in Docket No. RP00-336-002, APS/Pinnacle states that it is improper to apply the principles governing firm service on other pipelines to the El Paso system. APS/Pinnacle states that the mere existence of the pro rata allocation methodology for allocating available capacity among firm shippers on the El Paso system means that firm capacity is not analogous to firm capacity on other pipelines. Contrary to the suggestion of APS/Pinnacle, the Commission's regulations that define firm service apply to firm service on all pipelines. Firm service has the same attributes and must meet the same requirements on all pipelines. The Commission has not approved a different type of firm service on El Paso that is less firm or less reliable than firm service on other pipelines.

Moreover, service nomination strategies exacerbate the need for nomination allocations. El Paso's tariff provides for system-wide primary point access to receipt points, and pro rata allocations if nominations exceed capacity. CD customers cannot nominate quantities above their CD levels, but the FR shippers can and must nominate their full gas requirements, and thus do not have a specific volumetric limit on the quantities they can nominate. The FR shippers' nominations are limited only by the capacity of their delivery points. Non-specific primary receipt point rights and the pro rata allocation methodology were not issues at the time of the 1996 Settlement because there was excess capacity on El Paso at that time.

In the Topock proceeding, the Commission determined that El Paso's practice of prorationing primary firm capacity at the Topock delivery point and other delivery points was unjust and unreasonable because firm shippers were not receiving reliable firm service. The same reasoning is applicable here, and the Commission concludes that unspecified primary point access to receipt points and El Paso's pro rata allocation methodology is unjust and unreasonable because firm shippers are not receiving firm service, contrary to section 284.7 of the Commission's regulations. The Commission will, therefore, again exercise its authority under section 5 of the NGA and direct El Paso to implement a plan to establish specific primary point rights at receipt points.

B. Full Requirements Contracts on El Paso Are No Longer Just and Reasonable Nor in the Public Interest

While, as discussed above, there is no disagreement among the parties that El Paso has insufficient capacity to meet the needs of its firm shippers and that cuts in firm service occur on its system, the parties disagree as to the cause of the problems and the appropriate solution. The CD customers and El Paso attribute the routine pro rata cuts, at least in part,[26] to growth in FR demand and assert that some limit must be placed on the growth in demand permitted under those contracts. El Paso maintains that it is not obligated to build pipeline capacity to meet growing demands. The FR shippers, on the other hand, argue that the CD shippers have not shown that the increase in FR demand has caused the pro rata allocations, that they are legally entitled to transport their daily requirements and that the solution to the problems on El Paso is to require El Paso to expand its system, not to limit the demand under FR contracts.

Using the customers' data posted on El Paso's website regarding demands on its system, Joint Complainants calculate that EOC FR load on El Paso has increased by approximately 50 percent from 1995 to January 2001. These data indicate that for the first years after the Settlement, demand under the FR contracts was relatively small and steady. Joint Complainants assert that in 1995, the peak FR demand was 1033 MMcf/d; in 1996 it was 1135 MMcf/d; and in 1998 it was 1127 MMcf/d. Subsequently, the demands have increased significantly. In 1999 FR demand was 1300 MMcf/d, in 2000 it was 1400 MMcf/d, and in January 2001 it was 1500 MMcf/d. The TNMA Shippers acknowledge that their demand has grown by approximately 9.5 percent per year since the test period.[27] Again, there is no disagreement among the parties regarding the underlying facts, and that the volumes demanded under the FR contracts have grown significantly since the execution of the 1996 Settlement, approximately 50 to 70 percent. El Paso's August 16, 2001 data response projects that demand under the FR contracts will grow to over 2 Bcf in 2002.[28] In fact, FR shippers have now projected that their need in aggregate will total 3 Bcf over the next few years.

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[26]The CD customers also allege that the problem has been caused in part by El Paso overselling its system.

[27]They state that in the 1994-1995 test period, the aggregate FR non-coincident peaks were 969,961 Dth. They state that multiplying that number by 9.5 percent over six years equals 1,672,011 Dth, which is approximately equal to the 2000 aggregate FR of 1,664,294 Dth. This calculates to a growth in demand of 72 percent for the period 1994-1995 to 2000.

[28]The data response includes studies containing FR shippers' projected demand through December 2006. Study 4A shows that FR shippers project peak demands in excess of 2.8 Bcf. Joint Complainants state that additional planned electric generation projects in the Southwest, if constructed, will require an additional 2200-2900 Mmcf/d of capacity by 2004. Joint Complainants, pp. 19-20 and Exhibit E.

The FR shippers[29] argue, however, that the Joint Complainants have failed to show that the increase in FR demand is the cause of the reduction in service due to the pro rata allocations to firm service. APS/Pinnacle states that the complaint is void of any quantitative analysis of new capacity commitments entered into by El Paso since 1995 that could contribute to the problem.

The Commission does not suggest that there is a single cause of the capacity crisis on El Paso. As APS/Pinnacle suggests, El Paso has continued to remarket firm service capacity as contracts expire irrespective of current capacity availability on its system, and the impacts its actions may have on all other shippers.[30] Nonetheless, while the growth in FR demand may not be the only cause of the service degradation problem, it is the most significant part of the problem and any solution must tie future growth in FR customers' demands to appropriate allocations of costs related to those demands as well as to capacity expansions, so that this growth does not negatively impact service rights of other firm shippers. Plans for new gas-fired power plants indicate that future FR growth would be substantial, further exacerbating the situation. For example, APS's proposed Redhawk generation facility, projected to be in service in Fall 2002, seeks to obtain 410,000 Mcf/d under APS's FR contract, increasing APS's FR usage by over 600% from its billing determinant of 66,000 Mcf/d.[31] FR growth would greatly increase if this capacity were supplied under the FR contracts and the increased demand would cause additional cuts in firm CD service. In addition, these increases take place without any added revenue responsibility and provide no incentive for El Paso to build additional facilities.

The Commission finds that where capacity is constrained on a pipeline, permitting increased demand growth under FR contracts will necessarily further degrade firm service and result in additional pro rata cuts to firm nominations. This is inconsistent with the concept of firm service and with the Commission's regulations.[32] Therefore, the Commission finds that it is necessary to convert the FR contracts to CD contracts to remedy the unjust and unreasonable impact unrestricted demand growth has on all firm

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[29]E.g., TNMA, APS/Pinnacle, and Southwest.

[30]In Docket No. RP97-287-057, El Paso Natural Gas Co., 99 FERC ¶ 61,140 (issued May 1, 2002), the Commission expressed concern that El Paso had not demonstrated that it has the capacity to serve PPL EnergyPlus, LLC (PPL) on a firm service basis and suspended the effectiveness of its firm service agreement with PPL for five months.

[31]Joint Complainants, p. 19.

[32]18 C.F.R § 284.7.

shippers on the El Paso system. Continued unlimited growth of the FR contracts, without factoring rate and service consequences, is not in the public interest because it will continue to degrade firm service reliability.

In addition, the rates paid by the FR shippers do not ration capacity,[33] and provide unfair competitive advantages for new power plants that are served under existing FR contracts. Converting FR contracts to CD contracts will bring El Paso's operations more closely into compliance with the uniform business practices adopted by the North American Energy Standards Board (formerly GISB), Order Nos. 636[34] and 637,[35] and thus bring additional benefits to all of El Paso's customers. Further, because FR customers will have to bid for additional capacity, El Paso will have the economic incentive to build necessary capacity to serve growing demand.

The full requirements customers state that they must rely on the FR contracts because they are captive customers, yet FR contracts serve to keep them captive. The FR customers state that there has been significant growth in the population and economy of the region they serve. In a competitive market, there would be incentives for both El Paso and other pipelines to enter that market to supply and compete for the growth in business. However, the FR contracts remove that incentive since no new entrant to the market can compete with El Paso for customers that will have all their growth served

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[33]18 C.F.R. § 284.10(b)(1) (2001).

[34]Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation and Regulations of Natural Gas Pipelines After Partial Wellhead Decontrol, 57 Fed. Reg. 13,267 (April 16, 1992), FERC Stats. & Regs Preambles January 1991 - June 1996 ¶ 30,939 (April 8, 1992), order on reh'g, Order No. 636-A, 57 Fed. Reg. 36,128 (August 12, 1992), FERC Stats.& Regs. Preambles, January 1991 - June 1996 ¶ 30, 950 (August 3, 1992), order on reh'g, Order No. 636-B, 57 FED. REG. 57,911 (December 8, 1992), 61 FERC ¶ 61,272 (1992), notice of denial of rehearing (January 8, 1993), 62 FERC ¶ 61,007 (1993), aff'd in part and vacated and remanded in part, UDC v. FERC, 88 F.3d 1105 (D.C. Cir.1996), order on remand, Order No. 636-C, 78 FERC § 61,186 (1997), order on reh'g, Order No. 636-D, 83 FERC ¶ 61,210 (1998).

[35]Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services, FERC Stats. & Regs. Regulations Preambles (July 1996-December 2000) ¶ 31,091 (Feb. 9, 2000); order on rehearing, Order No. 637-A, FERC Stats. & Regs, Regulations Preambles (July 1996-December 2000) ¶ 31,099 (May 19, 2000), aff'd in part and rev'd and remanded in part, INGAA v. FERC, 285 F.3d 18 (D.C.Cir. 2002).

under their existing contracts. And, because FR customers are not subject to increased reservation charges with increases in demand, there is no economic incentive for El Paso to add needed capacity at Rate Schedule FT-1 commodity rates.[36] We find that the current FR contracts are a disincentive to pipeline-to-pipeline competition and provide no incentive for El Paso to provide for necessary expansion.[37] Once the FR contracts have been converted to CD contracts, FR customers will be able contractually to purchase transportation from pipelines other than El Paso. This will provide proper incentives and price signals for other pipelines to compete with El Paso and for El Paso to construct additional capacity to serve these needs.

The Commission's decision here is not premised on whether the level of growth in the FR demand was foreseeable at the time of the execution of the Settlement. The CD customers argue that full requirements contracts do not permit unlimited growth in demand, and do not permit growth that is unreasonably disproportionate to the expectation of the parties. SoCalGas cites caselaw decided under the Uniform Commercial Code (UCC) holding that a demand that is 60 percent in excess of an estimate is excessive,[38] and argues that therefore a several hundred fold increase in demand, such as sought by APS/Pinnacle, is an unacceptable modification of the FR contract. Similarly, in its comments filed at the April 16, 2002 public conference, Indicated Shippers argue that there are legal limits on the growth that can occur under full requirements contracts and that full requirements contracts should not be interpreted to permit unlimited growth.[39]

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[36]As discussed below, we conclude that the language of the Settlements does not place an unqualified obligation on El Paso to build additional facilities to serve FR growth, and conditions any such obligation on the economic feasibility of the construction. There appears to be no economic incentive for El Paso to construct facilities to serve customers that will pay only a commodity charge for use of the new facilities.

[37]It is true that El Paso has added the Line 2000 Project without any incremental surcharges. Line 2000 is the first phase of the conversion of the All American Pipeline to a natural gas pipeline, which will be integrated into the El Paso system in at least three separate stages.

[38]SoCalGas cites Shea-Kaiser-Lockheed-Healy v. Department of Water and Power (1977) 73 Cal.App.3d 679, 140 CalRptr. 884.

[39]Indicted Shippers cite, inter alia, Granite City Steel Co. v. FPC, 320 F.2d 711 (D.C.Cir. 1963).

The FR shippers,[40] on the other hand, argue that UCC case law is not applicable to these contracts. In any event, they argue, the type of growth that has occurred since the 1996 Settlement is consistent with the growth in the economy of the Southwest and was foreseeable at the time of the Settlement.[41] TNMA Shippers assert that the Commission has never placed quantitative limits on FR service and has repeatedly held that FR contracts entitle customers to take their full requirements daily.

The Commission recognizes that the courts have placed implied limitations on full requirements contracts. As the parties point out, these limitations are often related to foreseeability and the expectations of the parties. While the Commission is not suggesting that increases in demand under the FR contracts from new plants such as APS/Pinnacle's proposed Redhawk plant[42] were or should have been foreseeable at the time of the Settlement, even if they were, the Commission must consider the public interest in resolving capacity allocation issues where there is insufficient capacity on the pipeline to meet firm demand. The current routine reductions in firm service that will become greater as demand continues to grow without a concomitant increase in available capacity are not just and reasonable. Therefore, the Commission must provide a remedy that is in the public interest. It is the public interest, not whether these problems should have been foreseen at the time of the Settlement, that must guide the Commission's action.

Moreover, the Commission is establishing a procedure for the parties, in the first instance, to establish a reasonable limit on the amount of capacity that the FR customers can take in the future. The Commission believes that this procedure will allow El Paso and its customers to establish future CD entitlements for the current FR customers, taking into account the customers' needs. This approach is preferable to the Commission setting a limit on FR contracts based on its determination of what level of growth in those contracts was foreseeable and proportionate to the expectations of the parties.

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[40] E.g., APS/Pinnacle, TNMA Shippers, and Southwest Gas.

[41] TNMA Shippers cite statistics from the U.S. Census Bureau showing that between 1990 and 2000, the population of Arizona increased 40 percent, that of New Mexico by 20.1 percent, and that of Texas by 22.8 percent, compared to a 13 percent increase for the United States as a whole.

[42] See 95 FERC ¶ 61,461 (2001).

1. Conversion of the FR Contracts to CD Contracts Is Consistent with the Mobile-Sierra Doctrine

The FR shippers [43] argue that conversion of their contracts would involve material alterations of existing contracts, and that such changes cannot be made without meeting the higher public interest standard set forth in the Mobile-Sierra doctrine.[44] These parties argue that the Commission bears a heavy section 5 burden in abrogating existing contracts. APS/Pinnacle argues, citing Texaco, Inc. v. FERC,[45] that the Commission cannot rely on generic public interest findings in meeting this burden, but must make a particularized showing regarding the manner in which a particular contract harms the public interest and the extent to which abrogation or reformation mitigates the contract's deleterious effect.

The Joint Complainants, on the other hand, assert that Mobile-Sierra does not apply in these proceedings because some of the contracts for FR service provide for a future modification to the 1996 Settlement by the Commission and a renegotiation of the contracts to conform to any such modification.[46] The language cited by Joint Complainants, however, refers to any changes in the Settlement that might have been made by the Commission in its order approving the Settlement, not to changes to the Settlement after its approval. We find that the Mobile-Sierra doctrine applies in this case.

Under Mobile-Sierra, a pipeline cannot unilaterally change its contracts with its customers by making a section 4 filing. The Commission, however, retains its section 5 authority to modify contracts that it determines are not in the public interest. As the court

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[43]E.g., Joint Motion to Intervene and Answer of APS/Pinnacle in Docket No. RP01-484-000; Protest and Comments of TNMA Shippers in Docket RP01-484-000.

[44]FPC v. Sierra Pacific Power Co., 350 U.S. 348 (1956); United Gas Pipeline Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956).

[45]148 F3d.1091, 1097 (D.C.Cir. 1998).

[46]The Joint Complainants cite language of the FR contracts that provides that if there is a change in the Settlement, the parties agree to negotiate in good faith to "conform this Agreement [the FR contract] to the Stipulation and Agreement as so changed or modified." Joint Complainants cite as an example, Article 9.10 of the FR contract between APS and El Paso.

stated in UDC v. FERC,[47] "[u]nder § 5, 'the Commission has plenary authority to limit or to proscribe contractual arrangements that contravene the relevant public interests.'" But, only in extraordinary circumstances, and only where the public interest so requires, will the Commission order contract modification.[48] For example, the Commission has ordered contract modification in connection with its restructuring of the natural gas[49] and electric industries.[50]

In Texaco, Inc. v. FERC, cited by APS/Pinnacle and the TNMA Shippers, shippers challenged the Commission's authority to require a pipeline to file tariff sheets imposing the Straight Fixed Variable (SFV) rate design on shippers whose contracts specified Modified Fixed Variable (MFV) rates, and argued that this was a contract modification prohibited by Mobile-Sierra. The court held that the Commission's modification of the existing contracts could be upheld only if the Commission showed that the public interest had required it to intervene. The court further stated that the public interest that permits FERC to modify a contract is different from and more exacting than the public interest that FERC seeks to serve when it promulgates its rules. The court stated that "more is required to justify regulatory intervention in a private contract than a simple reference to

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[47]88 F.3d 1105, 1131 (D.C. Cir. 1996), cert denied, 520 U.S. 1224 (1997) (quoting Permian Basin Area Rate Cases, 390 U.S. 784 (1968)). See also, e.g., Wisconsin Gas Co. v. FERC, 770 F.2d 1144 (D.C. Cir. 1985), 476 U.S. 1144 (1986).

[48]See, Nevada Power Co. v. Duke Energy Trading and Marketing, L.L.C., 99 FERC ¶ 61,047 at 61,190 (2002).

[49]Order No. 636, supra.

[50]Order No. 888 Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded costs Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities Order No. 888 , 61 Fed. Reg. 21,540, at 31,664-65 (1996), FERC Statutes and Regulations, Regulations Preambles January 1991-June 1996 ¶ 31,036 (1996), order on reh'g, Order No. 888-A , 62 Fed. Reg. 12,274 (1997), FERC Statutes and Regulations, Regulations Preambles July 1996-December 2000 ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998), aff'd in relevant part, remanded in part on other grounds sub nom. Transmission Access Policy Study Group, et al. v. FERC, 225 F. 3d 667 (D.C. Cir. 2000), aff'd, New York v. FERC, 122 S. Ct. 1012 (2002).

the policies served by a particular rule."[51] The court affirmed the Commission's orders, stating that the Commission did not rest its reformation of the contracts on only the broad public interest underlying its policy favoring SFV, but also explained how retention of MFV on the particular pipeline would threaten the coherence of the national policy and distort the local gas market. The court found that the Commission had satisfied its obligation to articulate supportable and reasonable explanations of how the public interest required modification of a private contract.

There are extraordinary circumstances on El Paso that require, in the public interest, modification of the FR contracts. The Commission's determination that the public interest requires modification of the FR contracts is not based merely on generalized statements of policy goals, but is based on a detailed analysis of how the FR contracts on El Paso harm the public interest and how the conversion of those contracts will further the public interest. The Commission has explained in detail how growth under the FR contracts has resulted in pro rata cuts that have eroded firm service on El Paso, and how this has resulted in firm shippers paying for service they do not receive. It is in the public interest to have reliable firm service on El Paso, and the Commission has explained how modification of the FR contracts on El Paso serves that goal. All customers will ultimately benefit from reliable firm service on El Paso and from the establishment of the proper market incentives for expansion of the infrastructure that will result from conversion of the FR contracts to CD contracts.

TNMA Shippers assert that the Commission has approved FR contracts for several decades, and to find now that FR service is contrary to the public interest would be an arbitrary reversal of its own finding. The fact that the Commission approved FR contracts in the past does not mean that the Commission cannot modify FR contracts as it has done here when those contracts operate in a manner that is contrary to the public interest. In fact, the Commission has an affirmative duty not to turn a blind eye to the degradation of firm service on El Paso's system. For example, when supply shortages arose in the natural gas industry in the 1970's, the Commission found itself "impelled to direct curtailment on the basis of end use rather than on the basis of contract simply because contracts do not necessarily serve the public interest requirement of efficient allocation of a wasting resource..."[52] Here, the Commission has clearly explained the reasons for conversion of the FR contracts to CD contracts.

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[51] 148 F.3d at 1097.

[52] Order No. 467, 49 F.P.C. 85, 86 (quoting Arkansas Louisiana Gas Co., 49 F.P.C. 53, 66 (1973), reh'g, 49 F.P.C. 583 (1973), petition for review dismissed sub nom., Pacific Gas & Electric Co. v. F.P.C., 506 F.2d 33 (D.C.Cir. 1974).

TNMA Shippers also argue that modification of the FR contracts is not in the public interest because the FR shippers are generally captive customers who have relied on and continue to rely on their contracts to provide utility service to human needs customers and to keep industrial plants running. However, it is the Commission's responsibility in the first instance, to decide whether the modification of the contracts is in the public interest taking all factors into account including whether maintaining the status quo "cast[s] upon other consumers an excessive burden, or [is] unduly discriminatory."[53] Moreover, as explained below, the limitation of future growth under the FR contracts is consistent with the Commission's duty to protect captive customers.

2. Conversion of the FR Contracts to CD Contracts Is Consistent With Section 7 of the NGA

The FR shippers argue that conversion of their contracts to CD contracts at the billing determinant level as proposed by El Paso in its allocation filing and by Joint Complainants in their complaint would constitute an unlawful abandonment of certificated full requirements service and substitute partial requirements service in its place.[54] These parties argue that an abandonment within the meaning of section 7(b) occurs whenever a natural gas company reduces a significant portion of a particular service dedicated to the interstate markets,[55] and when there is a reduction or alteration in overall service.[56] They argue that FR shippers are legally entitled to transport their daily requirements, and that full requirements service cannot be abandoned without a finding under section 7 of the NGA that abandonment is in the public interest.

These parties further argue that the Commission cannot make this public interest finding here because the FR shippers are, for the most part, captive customers that transport their daily full requirements to meet their utility obligations to their own

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[53]FPC v. Sierra Pacific Power Co., 350 U.S. 348, 355 (1955).

[54]See, e.g., Comments of East of California Shippers in Opposition to Indefinite and Unlawful Capacity Allocation Proposal, Docket No. RP00-336-000, filed May 17, 2001 at 21-22; Protest and Comments of TNMA Shippers in Docket No. RP01-484-000, filed August 2, 2001 at 10-15.

[55]The EOC Customers cite Reynolds Metals Co. v. FPC, 534 F.2d 379, 384 (D.C.Cir. 1976).

[56]The EOC Customers cite Tennessee Gas Pipeline Co. v. FERC, 972 F.2d 376, 384 (D.C.Cir. 1992).

customers. If their entitlements were reduced, these shippers argue,[57] it would be impossible for them to serve their own customers or maintain their business operations. TNMA Shippers allege that if entitlements were reduced, there would be rolling blackouts throughout Texas, New Mexico, and Arizona, and many businesses and communities would be harmed. Further, these parties argue, FR distributors and electric utilities serve human needs customers, and the curtailment of gas and electricity would have disastrous public health impacts on all sectors of the economy in the affected states. This result, they argue, is not consistent with the public convenience and necessity. Further, they argue, it contradicts the Commission's charge under section 7(b) of the NGA to protect the rights of existing shippers. Consistent with that obligation, TNMA Shippers argue, the Commission should find that El Paso has partially abandoned service to its firm customers and that El Paso must provide facilities to provide service to all firm customers.

The circumstances before us are very different from the circumstances in the cases cited by the FR customers. In this case, the Commission finds under section 5 of the NGA that continued growth in demand under the FR contracts imperils the provision of firm service on El Paso's system and thus is not just and reasonable in the current circumstances on El Paso's system. Therefore, the Commission is directing El Paso to convert these FR contracts to CD contracts and is providing the parties with an opportunity to establish a CD entitlement for these shippers that takes into account their current needs. As the Commission has explained, this conversion is necessary under section 5 of the NGA to protect all customers and the public interest and is consistent with the Mobile-Sierra doctrine.

The conversion of the FR contracts to CD contracts is also fully consistent with the requirements of section 7 of the NGA regarding abandonment of service and the Commission's obligation to protect captive customers. The protection afforded customers with regard to abandonment of their Part 284 service is intended to protect captive customers from the monopoly power of the pipeline and to permit captive customers to continue to receive the historical service upon which they have relied, as long as they are willing to pay the maximum rate for that service.[58] As the Commission explained in Order No. 637, this abandonment protection applies with regard to the captive customer's historical capacity. It is a limited right and is intended as a defense against the pipeline's

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[57]See, e.g., Protest and Comments of TNMA Shippers in Docket No. RP01-484-000.

[58]Order No. 636, aff'd in pertinent part, UDC v. FERC, 88 F.3d 1105 (D.C.Cir. 1996), cert. denied, 520 U.S. 1224 (1997); Order No. 637 at 31,335 - 340.

monopoly power, not as a mechanism to award an existing customer a preference in obtaining additional service.[59] Further, the protection against abandonment does not give a captive customer a right to discounted service in the future.[60] Continued growth in demand under the FR contracts and the addition of new facilities to be served under those contracts are not the within the scope of the abandonment protection.

The Commission is giving the parties an opportunity to establish CD entitlements for the FR shippers that take into consideration the FR shippers' current needs and use of the system on a seasonal basis. It is therefore consistent with the policy of protecting the captive customers' historical service. Moreover, in this case, the Commission is affording the FR customers additional protections and is giving these customers a preferential opportunity to obtain capacity from El Paso above their new CD entitlements. Therefore, the Commission is directing El Paso to make additional capacity available to the FR customers through capacity turnback, adjustments for seasonal usage, and a priority for capacity under the Line 2000 PowerUp. These steps will assure that all FR shippers will receive a fair allocation of available capacity needed to meet their load requirements.

The capacity rationalization process approved in this order will enable the FR shippers to receive service at the capacity levels they used on the system in 2001. Therefore, the Commission is approving a capacity allocation method that will continue service at existing levels, consistent with the abandonment protection.

3. Modification of the Settlements to the Extent Necessary to Convert the FR Contracts to CD Contracts is Just and Reasonable and in the Public Interest

The FR customers also argue that adoption of El Paso's proposal would unlawfully abrogate both the 1990 and 1996 Settlements. Southwest Gas argues that FR service is explicitly part of both Settlements, and any acceptable allocation proposal must preserve FR service rights, including the right to grow. APS/Pinnacle states that at the time of the 1996 Settlement, the FR customers agreed to pay millions of dollars to resolve the problem of capacity turnback in exchange for a guarantee of rate certainty and the firm

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[59]Order No. 637 at 31,339. This is consistent with the court's decision in Municipal Defense Group v. FERC, 170 F.3d 197 (D.C.Cir. 1999), upholding the Commission's decision in Texas Eastern Transmission Corp., 79 FERC ¶ 61,258 (1977), reh'g, 80 FERC ¶ 61,270 (1977), that small customers had special treatment for their existing service, but they must compete on an equal basis for additional capacity.

[60]Order No. 637 at 31,631-634.

capacity needed to meet their growing electric demands over the 10-year Settlement period. APS/Pinnacle states that the FR shippers would not have agreed to the 1996 Settlement if there had been a possibility that their rights as FR customers would diminish. The FR customers argue that modifying the Settlement halfway through its term is contrary to the public interest because it undermines the integrity of each settling party's firm contract and precludes the parties from recognizing the benefits of their bargains. They also argue that abrogating the Settlement would discourage settlements, contrary to the Commission's policy of favoring settlements.

It is the Commission's policy to encourage settlements[61] and the Commission is extremely reluctant to alter a settlement during its term. However, the circumstances on El Paso have changed drastically since the Settlements were executed. El Paso benefitted from the customers' sharing the risks and costs of the unsubscribed capacity. The customers benefitted from rate stability. FR customers were allowed to retain their FR contracts even though at the time of the Settlement, most other pipelines no longer offered FR contracts.[62] All customers realized benefits from the flexibility resulting from a largely unsubscribed pipeline. Finally, all customers benefitted from the revenue sharing provision,[63] since El Paso was able to sell its unsubscribed capacity at maximum tariff rates.

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[61]In this proceeding, the Commission encouraged the parties to resolve the capacity allocation issues on El Paso by settlement. After numerous attempts to settle these issues, including referral of the issues to the Commission's Dispute Resolution Service, the parties were not able to reach an agreement. At the same time, the situation on El Paso is, in the words of one of the FR customers, in a crisis, and action must be taken to resolve the issues.

[62]Instead, most pipelines offer fixed levels of no-notice service.

[63]The 1996 Settlement resolved the capacity turnback problem through an agreed-upon sharing of the risk of unsubscribed or undersubscribed capacity. Specifically, the 1996 Settlement provided that during the first eight years of the Settlement period, El Paso's customers would be responsible for 35 percent of the revenue loss assignable to unsubscribed capacity, while El Paso would bear 65 percent of that loss. As a quid pro quo, customers would share 35 percent of the revenues from future sale of the unsubscribed capacity exceeding a specified "Revenue Crediting" threshold. In addition, El Paso's historical firm customers agreed to pay an additional risk sharing amount of approximately $250 million. After the first eight years, El Paso would be at risk for 100 percent of the loss from unsubscribed capacity.

While the Settlement was a reasonable resolution of the issues facing El Paso and its customers at that time, the circumstances that made the Settlement reasonable do not exist today. Instead of facing capacity turnback, El Paso lacks sufficient capacity to meet the demands of its firm customers. As explained above, the result has been that there are regular cuts in firm service on El Paso, and firm service is not reliable. Unless the Commission makes some adjustment to the terms of the Settlement to reform the FR contracts and establish specific receipt point rights, the problems of unreliability on El Paso will continue and worsen.[64]

While the Commission rarely alters an approved settlement, it has not only the authority, but also the responsibility under section 5 of the NGA to make an adjustment to a settlement if the terms of the settlement have become unjust and unreasonable and the settlement operates in a way that is contrary to the public interest.[65] The Commission has a responsibility to exercise its authority in the circumstances here to provide a solution to the capacity allocation problems on the El Paso system. The Commission has attempted to minimize changes to the Settlement while taking action to alleviate reliability problems. The Commission does not propose to alter the Settlement rates. The FR shippers will continue to benefit from the Settlement because they will continue to pay their current demand charges based upon their billing determinant levels. To the extent that establishing specific service entitlements under the existing FR contracts is a modification of the Settlement, that modification is necessary and is in the public interest.

4. Methodology for Converting FR Contracts to CD Contracts

A number of different entitlement allocation methodologies have been proposed during the course of the proceedings, some of which incorporated conversion of FR contracts to CD contracts and some of which did not. El Paso in its initial proposal filed March 28, 2001 allocated capacity based on billing determinants. FR shippers offered alternatives to El Paso's proposal using non-coincident peak demand. At the March 13, 2002 Commission meeting, the Commission advisory staff apprised the Commission of the alternatives and presented another solution that would convert FR service to CD service with entitlements reflecting latest practices and the Commission's traditional system peak allocation approach. At the April 16, 2002 public conference, the parties presented further variations to consider.

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[64]As discussed above, the demand under the FR contracts is expected to increase. FR shippers have now projected that their needs in aggregate will total 3 Bcf over the next few years, more than a 300% increase.

[65]E.g., UDC v. FERC, 88 F.3d 1105, 1131 (D.C. Cir. 1996).

The Commission will not approve El Paso's proposal to allocate capacity to the FR shippers at their billing determinant level. While billing determinants determine the current cost allocation to the FR shippers pursuant to the 1996 Settlement, they do not reflect the current use of the system. Use of billing determinants would ignore all growth that has occurred since the 1996 Settlement, and would be unreasonable. A reasonable conversion methodology should reflect the current practices of these shippers.

The Commission also finds that the proposals of Salt River and Southwest Gas to convert FR shippers to annual CD levels based on historical non-coincident peaks are not reasonable. Non-coincident peaks represent a shipper's peak demand for the year, the one day when a shipper experiences its highest demand for the year. Shippers are likely to experience non-coincident peaks on different days and sometimes different seasons of the year. It is for that reason that pipelines do not design their systems based on non-coincident peaks. To do so would result in a drastically overbuilt pipeline, because the pipeline would not need to serve each shipper's non-coincident peak on the same day. Because shippers have different customer mixes, different locations with varying weather patterns, and different access to alternate fuels and supplies, one set of shippers' high demand on a given day will often be offset by another set's lower demand. Shippers would likely be unwilling to pay the high costs of construction necessary to build and reserve capacity sufficient to serve non-coincidental peak demands. In addition, because there is insufficient capacity to serve both the CD contracts and FR non-coincident peak demands, use of non-coincident peak would result in a reduction of the CD shippers' allocation below the current CD level. The Commission finds that it is not just and reasonable to allocate less capacity to these firm CD shippers than the capacity for which they have contracted and paid.

The Commission believes that a reasonable conversion methodology reflects the current practices of the FR shippers within the current capacity and does not allocate less capacity to any shipper than it is paying for. A reasonable conversion methodology thus does not reduce CD shippers' entitlements, and does not reduce FR shippers' entitlements below their 1996 Settlement billing determinants.[66]

In this proceeding, full requirements shippers have raised two major concerns with the use of a system peak demand for allocation purposes. First, shippers express the need to reflect seasonal variations in their entitlements. They argue that some shippers are summer peakers (e.g., electric generation) and others are winter peakers (e.g., space heating)and that using shippers' seasonal needs to "sculpt" their entitlement allocations

[66]To the extent El Paso can adjust demand levels to accommodate seasonal variations in FR customers' demands, it must do so.

will result in more equitable and accurate contract entitlements. Seasonal entitlement allocations will allow shippers to obtain capacity for the seasons or months that they need it, thus freeing capacity the rest of the year for use by other shippers with different seasonal needs.

Second, the shippers stress their individual peak demands (i.e., their non-coincidental peak) did not occur on the December 12, 2001 system peak day, and that use of such a system peak day demand does not reflect their needs. The Arizona Corporation Commission argues that adoption of an entitlement allocation based on the system peak day would lead to blackouts, curtailments, increased pollution, and significantly increased energy costs in Arizona.[67] In addition, FR shippers argue that they will be subject to significantly increased costs when they attempt to purchase additional capacity, because it will be a seller's market for capacity.[68] Further, they allege, the lack of a price cap on short-term released capacity will deter long-term releases and will allow releasing shippers to command high prices for peak capacity that the FR shippers will need to serve core needs.[69] El Paso Electric Company suggests that the appropriate level of contract demand might be the midpoint between a shipper's 1996 Settlement billing determinants and its non-coincidental peak.[70]

The conversion methodology shall initially allocate among the FR shippers the system capacity that is currently not under contract to CD shippers. Additionally, as discussed below, El Paso has been authorized to add 230,000 Mcf/d with its Line 2000 project. El Paso has dedicated the Line 2000 capacity for system use. That capacity is therefore available to be allocated to FR shippers to use this Fall. The full existing capacity plus the Line 2000 capacity minus the full CD shippers' contract levels and a reasonable amount to serve the FT-2 shippers, is the amount available to be allocated to the FR shippers at no additional charge above their current demand charge responsibility. The initial entitlements under the new CD contracts are, however, only the starting point for providing capacity to the FR shippers.

A capacity rationalization process, including capacity turnback, adjustments for seasonal usage, and capacity release, will provide additional capacity to meet FR demand. For example, Burlington Resources and other shippers indicated at the April 16 conference

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[67]Tr. at 50.

[68]Tr. at 78.

[69]Id.

[70]Tr. at page 107.

and in their written comments that they would be willing to turn back 725,719 Mmcf for the summer months and 592,719 Mmcf for the winter months.[71] In addition, El Paso offered, at the April 16 conference, to work with its shippers to "sculpt" (incorporate seasonal variations into) the FR entitlement allocations.

Other parties at the April 16 conference asserted that the customers themselves were better suited to determining their own needs and should have a part in the entitlement allocation process. After consideration of the comments, proposals, and alternatives, the Commission concludes that it is appropriate to take an approach that incorporates many of the ideas and responds to many of the concerns raised by various parties. As noted above, we will not order a reduction of CD service. In addition, we will not specify individual CD entitlements for the FR shippers at this time. It is the Commission's desire that the parties who utilize the system involve themselves in the solution. The Commission will therefore direct El Paso and its customers to take the available capacity remaining that is not contracted for FT-1 CD service (or needed to serve FT-2 demand) and allocate that capacity among the FT-1 FR shippers as their new CDs. At the public conference, El Paso remarked that it would be able to deliver 5,400 Mmcf/d with the capacity to be provided by the PowerUp on a peak day.[72] In this way the FR shippers can decide among themselves how to divide up the capacity and whether to use seasonal and/or annual entitlement allocations. This represents their initial entitlements and does not require a redistribution of demand charge responsibility.

We direct El Paso and its customers to meet as soon as possible and as often as necessary to establish CD entitlements for each FT-1 FR shipper. The meetings should be in El Paso's service territory to facilitate participation of the parties' business and technical staff.

Once the initial CD entitlements are set, El Paso is directed to initiate a capacity rationalization process, as discussed at the April 16 conference,[73] in which current shippers are afforded an opportunity to turn back capacity, and converting FR shippers can purchase that capacity to augment capacity assigned during the conversion process. For the initial CD entitlements, the Commission will not require that costs be reallocated (although the parties may agree otherwise). In that way, the FR shippers are converted to CD entitlements at levels that can reliably be met at no additional charge above the Settlement rates. For any capacity purchased through turnback or capacity release, the

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[71] E.g., Tr. at 137.

[72] Tr. at 17.

[73] Tr. at 17-21.

converting FR shipper would pay the appropriate reservation charge. As a result, while demand charge responsibility may shift from one shipper to another, the total cost recovery will be unchanged. El Paso will remain revenue neutral as a consequence of the turnback. Finally, once the capacity rationalization process is complete, El Paso will then allocate primary receipt point rights among all CD and converting FR shippers following an iterative process, described later in this order. After reviewing the April 30, 2002 comments which detail amount of capacity that the shippers are willing to turnback,[74] and the restated FR needs, it appears that there should be sufficient capacity available to meet current needs as a result of this process.

The Commission will require El Paso to file a report with the Commission by September 3, 2002, detailing the steps that were taken (the new CD entitlements, the amount of turnback, etc.) and indicating the new CD levels for the CD and former FR shippers resulting from the capacity rationalization process and the receipt right allocations for each shipper resulting from the iterative process. By August 1, 2002, El Paso must report to the Commission whether the parties have been able to agree upon FR customers' entitlements under the new CD contracts. If the parties are unable to agree to entitlements, the Commission will establish appropriate CD entitlements for the converted contracts and will issue a further order to specify how entitlements should be allocated.

We are mindful of the conflicting timing concerns of the CD and FR shippers. The CD shippers demand immediate action to end pro rata service reductions.[75] They seek assurances that the financial losses they have suffered over the past three years will come to an end. The FR shippers, on the other hand, demand sufficient time to prepare for a limit to FR service.[76] They argue that they have made significant financial investments (for example, to build new generation plants) in reliance on the terms of the 1996 Settlement which ensures continuation of full requirements service through December 2005. They also argue that time is needed to arrange for alternate supplies and services if they are allocated less capacity than is needed to serve their core needs. The Commission finds that it is paramount to restore certainty and reliability to firm service on El Paso's system. We will therefore order FR service to be converted to CD service effective November 1, 2002. CD shippers will thus have certainty going into the winter heating

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[74]The comments reflect that the shippers, in total, may be willing to turn back over 725,000 Dth/d of summer capacity and close to 600,000 Dth/d of winter capacity. See commends filed by Burlington, Dynegy, Aera, Coral Energy, Occidental, Texaco, ONEOK, Southern California Generation Coalition, and Aquila.

[75]Tr. at 142, 146.

[76]Tr. at 57, 74-75.

season, and FR shippers, many of whom are summer peakers, will not be impacted this summer season and will have nine months to prepare for the 2003 summer season. In addition, the November 1, 2002 effective date will provide the parties the time to participate in the solution.

C. El Paso's Service Obligations

1. The Need to Make Additional Capacity Available to the Firm Shippers

All of El Paso's customers, both FR and CD, have argued in these proceedings that the capacity problems on El Paso have been caused, at least in part, by El Paso's failure to meet its service obligations to its firm customers. In Docket Nos. RP01-484-000 and RP01-486-000, the complaining shippers ask the Commission to order El Paso to expand its system and use that expanded capacity to satisfy its existing contractual obligations. The shippers argue that El Paso is obligated under Article 16.3 of the Settlement[77] to maintain quality and quantity of service. In addition, in Docket No. RP01-484-000, Joint Complainants argue that the Commission has authority under sections 5 and 7 of the NGA to require El Paso to comply with its certificate, contract, and Settlement obligations by ordering additional expansions and requiring the expansion capacity to be used to satisfy El Paso's existing firm contractual obligations.

Similarly, in Docket No. RP01-486-000, TNMA Shippers argue that El Paso has a legal obligation to maintain system capacity sufficient to meet all of its contractual commitments to provide firm transportation. They argue that a pipeline may be deemed to have violated section 7(b) of the NGA when the physical capacity of the pipeline is below the capacity required by its certificated contracts,[78] and that a pipeline is obligated to

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[77] Article 16.3 of the Settlement provides:

> 16.3 Service Obligations. El Paso agrees and confirms that, during the effectiveness of this Stipulation and Agreement, it will maintain and operate facilities sufficient to satisfy and perform the service obligations with respect to both quality and quantity of service imposed upon it by, and subject to the conditions applicable to, the provisions of this Stipulation and Agreement and its firm TSAs in effect on December 31, 1995.

[78] TNMA Shippers cite Columbia Gas Transmission Corp., 80 FERC ¶ 61,220 (1997).

maintain its facilities in a manner that will allow it to serve up to certificated levels or seek abandonment of capacity that was certificated but is no longer available.[79]

As an immediate step, TNMA Shippers ask that El Paso be required to dedicate the north-south capacity of its Daggett to Ehrenberg Line in California and the capacity it will be adding through compression to its new Line 2000 to fulfill its existing firm contractual obligations. Joint Complainants assert that any proposed expansion should be accompanied by a capacity rationalization process that would permit existing firm shippers to turn unwanted capacity back to the pipeline.

In the comments filed by the parties in connection with the April 16, 2002 public conference, the parties again argue that the Commission should require El Paso to meet its service obligations.

In its answers to the complaints, El Paso argues that it has provided firm service to FR and CD customers consistent with its contractual obligations, the capacity allocation provisions of its tariff, and the service obligation set forth in the 1990 Global Settlement. El Paso asserts that the parties to the 1990 Settlement specifically contemplated that a pro rata allocation of capacity might be required, and agreed to the allocation procedures now used by El Paso. In addition, El Paso asserts, the Global Settlement provides the circumstances in which it would be required to expand its system, and the parties agreed that El Paso would expand its system only when economically justified. El Paso states that the construction of additional capacity to serve the FR shippers at a commodity rate of two cents per Dth is not economically justifiable. Further, El Paso argues, citing Panhandle Eastern Pipeline Co. v. FPC, 204 F.2d 675 (3rd Cir. 1953), that the Commission does not have authority to order a pipeline to expand its mainline capacity. Therefore, El Paso asks that the Complainants' requests that El Paso be required to expand its system be denied.

However, since the filing of its responses in the complaint proceedings, El Paso has made a commitment to expand its transmission capacity by implementing its Line 2000 PowerUp project. At the April 16, 2002 public conference, El Paso committed that it would add up to 320,000 Mcf/d of new capacity through additional compression on its Line 2000 project.[80] El Paso stated that this additional compression, in combination with the proposal to convert FR contracts to CD contracts based on a system peak, should

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[79]TNMA Shippers cite Maritimes and Northeast Pipeline, L.L.C., 80 FERC ¶ 61,136 at 61,476 (1997).

[80]Tr. at 13-14.

eliminate the need for any pro rata allocations except in circumstances related to maintenance or force majeure.[81] Thus, while the Commission has stated that the decision whether to undertake to build additional capacity is a business decision that is left to the pipeline in the first instance under the NGA,[82] in this case, El Paso has committed to expand its capacity.[83]

The Commission further finds that El Paso, with respect to its obligation to provide firm shippers with the firm service for which they have contracted, must reasonably insure the quality of firm service, and that its actions do not degrade the quality of such service. In this regard, and in accordance with the provisions of the 1996 Settlement and the Commission's regulations, the Commission advises El Paso that it may not enter into new firm service contracts unless it can demonstrate that it has available capacity to provide the service.[84] Further, the Commission will require, during the pendency of the Settlement, that El Paso must first offer firm capacity that becomes available to existing shippers.

2. Flexible Receipt and Delivery Points

In Order No. 637, the Commission instituted proceedings to, among other things, review pipeline tariffs to insure shippers could flexibly and efficiently use the services for which they have contracted, and to insure there were no impediments to the use of third

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[81]Tr. at 14.

[82]E.g., El Paso Natural Gas Co., 54 FERC ¶ 61,316 at 61,924 (1991). See also Panhandle Eastern PipeLine Co. v. FPC, 204 F.2d 675, 680 ("Congress intended to leave the question whether to employ additional capital in the enlargement of its pipeline facilities to the unfettered judgment of the stockholders and directors of each natural gas company involved.")

[83]The Commission is committed to expediting the handling of El Paso's application for the PowerUp Project to ensure that the additional capacity is brought on-line as soon as possible. The Commission expects that El Paso will do all it can to expedite this process by filing a complete application. El Paso indicated in its August 23, 2001 data response that it could have an application before the Commission by March 2002, and stated at the April 16, 2002 public conference that it was preparing to file an application.

[84]This does not include capacity on lateral expansions to serve new markets, such as the Samalayuca lateral, 98 FERC ¶ 61,096, reh'g denied, ¶ 61,110 (2002).

party services. Several parties to these proceedings have voiced and filed comments (including Southwest Gas) requesting that El Paso be required to permit backhaul/displacement transactions from interconnections at or near the California border.

El Paso's tariff does not specifically allow such transactions. The Commission has found in numerous orders on Order No. 637 compliance filings, that pipelines must permit shippers to nominate service that would result in a change of flow under a service agreement. However, pipelines are not required to accept or permit backhaul transactions to the extent such transactions would negatively impact forward haul transactions or could not be operationally guaranteed. Further, in these orders, the Commission has recognized that backhaul nominations under what would otherwise be a forward haul transaction, fundamentally change the transaction, and only need be provided on a secondary priority basis. While the Commission has not completed its review of El Paso's Order No. 637 compliance filing, it must revise its tariff to permit those nominations and transactions. To the extent customers can avail themselves of these transactions, they may be able to increase capacity utilization of the El Paso system and gain access to gas storage facilities in California.

3. Demand Charge Credits

Joint Complainants assert that it is unjust and unreasonable for El Paso to charge for firm service that it does not provide. They assert that by overselling its system, failing to limit FR usage to a reasonable level, and selling 1.2 Bcf of available capacity to its affiliate, El Paso is reaping a windfall at the expense of the CD shippers who cannot use the firm capacity for which they are paying. Joint Complainants argue, citing Tennessee Gas Pipeline Company,[85] that El Paso should be required to credit firm transportation demand charges for any firm service that it cannot schedule for any reason other than force majeure.

In response, El Paso argues that pro rata allocation of firm service was specifically contemplated by the parties to the Settlements, and that El Paso has complied with the terms of these Settlements, its contracts, and its tariffs in providing firm service to its CD customers. El Paso states that the Commission has addressed the issue of whether a pipeline is obligated to issue demand charge credits in the context of each pipeline's tariff and service agreements. El Paso argues that in this case the Joint Complainants have pointed to no provision of the tariff, the service agreements, or the settlements that sets forth an obligation of El Paso to waive demand charge payments in the event the shipper's nomination is not scheduled due to the pro rata procedures. El Paso states that since the

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[85] 71 FERC ¶ 61,399 at 62,580 (1995).

CD customers were aware of the possibility that their receipt point nominations might not be scheduled because of the capacity allocation procedures in El Paso's tariff, it was incumbent on them to insist that the Global Settlement provide them with the demand charge credits that they now seek. El Paso argues that because it has complied with its contractual, tariff, and settlement obligations, no demand charge credits can be ordered in this proceeding.

El Paso further argues that in the Tennessee decision cited by Joint Complainants, the Commission did not mandate credits in all circumstances other than force majeure, but instead stated that a pipeline should be able to perform the service it has contracted to perform. El Paso states that in these circumstances it is performing the service it contracted to perform, in accordance with the allocation provision of the Settlement. El Paso states that the flaw in Joint Complainants' argument is that they assume that because gas does not always flow on the basis of their nominations, it follows that they have not received the service that they contracted to receive.

The nature of firm service is set forth in the Commission's regulations: firm service is service that is not subject to a prior claim by another customer.[86] As explained above, firm service has the same attributes and must meet the same requirements on all pipelines. There is not a different type of less-firm firm service on El Paso. A shipper contracting for firm service, as compared to interruptible, pays the pipeline a charge to reserve capacity on the pipeline in addition to the volumetric charge for actually transporting the gas. If the reservation portion of the firm transportation rate does not in fact reserve capacity on the pipeline, that charge is unjust and unreasonable because the shipper is paying for a service that it does not receive. If a shipper is not guaranteed capacity on the pipeline to transport its contract demand, then the service is not firm service, but is interruptible service. It is not just and reasonable to charge a shipper the higher firm rate if the service the shipper receives is interruptible.

In the Tennessee decision cited by the parties, the Commission stated that pipelines should be able to provide the service they have contracted to perform, and that it is therefore reasonable for pipelines to provide demand charge credits when they interrupt service that they have contracted to perform, except where service is interrupted by force majeure. Contrary to El Paso's argument, this decision was not based on the particular provisions of the contracts involved, but on the nature of any contract for firm service. If firm service is interrupted to schedule service for another customer, that service is not firm and is not the service for which the CD customer contracted and pays.

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[86]18 C.F.R. § 284.7 (2001).

A pipeline should not contract to provide more firm service than it has the capacity to provide. If El Paso sells more firm service than it can provide, and if it collects reservation charges for capacity that cannot be reserved, it is charging the customers an unjust and unreasonable rate. El Paso reasonably applied the Settlement provisions concerning pro rata allocations where there was insufficient capacity to meet demand for firm service. However, the Settlement provisions regarding pro rata allocation have led to the unreliability of firm service on El Paso and are no longer just and reasonable. Therefore, El Paso must prospectively provide firm service as contemplated by the Commission's regulations. When it is unable to do so, El Paso will be required to provide charge credits to its CD customers when it is unable to transport nominated volumes for reasons other than force majeure.

After the allocation process is complete, shippers will have specific receipt point rights at individual pools. The aggregate rights at any given pool should not exceed the maximum capacity at that pool or the mainline capacity for El Paso to transport the aggregate volumes. Therefore, after the capacity rationalization process is complete, El Paso should be able to transport all nominated volumes, except in circumstances of force majeure. We will direct El Paso to credit firm transportation reservation charges for any firm service that it cannot schedule for any reason other than force majeure, after November 1, 2002. El Paso shall file revised tariff sheets to reflect this reservation charge crediting requirement.

In addition, KN Marketing asked the Commission to order El Paso to refund all reservation charges KN Marketing has paid with respect to allocations that were not excused by force majeure in the East End. As explained above, the Commission is acting under section 5 of the NGA to establish just and reasonable allocation procedures on El Paso, including the crediting of demand charge credits for firm service that is not scheduled for reasons other than force majeure. Refunds are not available under section 5, and therefore KN Marketing's request for refunds is denied. Revenue credits will be available on a prospective basis.

D. Pooling

In its Topock order, the Commission found that El Paso's current capacity allocation methodology is unjust and unreasonable because it creates uncertainty with respect to the rights of firm shippers to receive firm service. The Commission required El Paso to file a proposal to allocate specific receipt point rights to its customers. The March 28, 2001 proposal filed by El Paso in compliance with the Topock order sets forth a methodology for assigning specific receipt point rights that is the subject of this order, as described more fully in Appendix A. The Commission has previously found that unspecified rights have led to the difficulties experienced in El Paso's primary pools.[87] The Commission finds the continuation of the practice of using unspecified receipt point rights is unjust and unreasonable. Based on the finding that systemwide flexible receipt point rights, as they operate on El Paso's system, are unjust and unreasonable, the Commission will direct El Paso to assign specific primary receipt point rights, as described more fully below.

1. El Paso's Proposal

In the March 28 filing, El Paso also proposes to change the number of pools on its system. El Paso proposes to replace the existing San Juan pools (Bondad and Blanco) with four pools (Bondad Station, Bondad Mainline, Blanco, and Rio Vista). The existing Anadarko pool would be replaced with three pools and the three Permian basin pools would be replaced with thirteen pools.

Pooling and the aggregation of supplies in the supply basins have been a long standing practice on El Paso's system that predates Order No. 636. El Paso's pooling points are located downstream of individual receipt points, where various supply sources merge or where pipeline capacity may be constrained. El Paso's current pooling arrangements encompass a vast network of liquid trading contracts and transportation contracts that come together in its current six basin pools. El Paso tracks these transactions. In the past, El Paso expressed concerns that the large number of pooling transactions can cause delays in the scheduling process. Additionally, El Paso has expressed concerns about matching customer supply rankings as a result of looped transactions.[88] El Paso indicates it was able to accommodate all pooling transactions, including unlimited looped transactions, when it had four days to schedule. Now with the standardized North American Energy Standards Board (NAESB) rules that provide for four intra-day nominations during the scheduling process, it has become increasingly difficult to track the pooling transactions when combined with downstream constraints that require El Paso to reduce customers' nominations pro-rata. El Paso indicates that pro-rata reductions are necessary due to force majeure or because shippers have nominated more

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[87] The Commission has previously indicated that the lack of specific receipt point rights creates uncertainty and is the main cause of the pro rata allocations based on nominations in El Paso's pools. See El Paso Natural Gas Company, 89 FERC ¶ 61,160 at 61,453 (1999).

[88] A looped transaction is one in which ownership of the gas may change several times without physical movement of the gas.

gas from a specific receipt point in the pooling area than the receipt point has the capacity to handle.[89]

El Paso states that its proposal would reduce the number of transactions in a pool and narrow the areas of constraint. El Paso states that its proposal to move from six to twenty pools is an attempt to achieve a compromise between service reliability and liquidity, preserving some of each. El Paso purports that smaller pools will provide more certainty and allow El Paso to better accommodate shippers' rankings of supply. El Paso states that it set the boundaries for its proposed twenty basin pools to group together system segments having similar operational characteristics.

El Paso cites the Bondad pool in the San Juan Basin to illustrate how it set pool boundaries. El Paso explains that it divided the Bondad pool into two pools: One north of the Bondad compressor station (Bondad Station pool) and one south (Bondad mainline). El Paso would allocate specific receipt rights to customers at the Bondad Station pool equal to the takeaway capacity at the compressor station. Prior to the division, Bondad shippers both south and north of the compressor station were included in the pro-rata reductions in the pool although the southern customers should not have been affected by the actual physical constraint at the compressor station. El Paso does not provide any other examples of constraints on its system justifying the expansion of pools in the other basins.

2. Customers' Response

Many commenters object to El Paso's proposal because they have different ideas about the appropriate balance between supply certainty and market liquidity. Some commenters, primarily those whose business relies on trading within the pools, believe that moving from six to twenty pools will unnecessarily reduce liquidity and the ability to aggregate supplies. Other commenters, primarily those who have contracts at specific plant outlets or wellheads, argue that receipts should be allocated back to specific receipt points to maximize reliability. Others would like the option of allocating to specific receipt points or pools.

The parties who commented on the pooling proposal uniformly object to El Paso's proposal to expand the number of pools.[90] The commenters conclude that 20 pools are not

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[89] El Paso data response filed August 23, 2001, Response to Question No. 2.

[90] In addition to individual comments opposing the pooling proposal, a diverse

(continued...)

necessary, not justified, and not supported by El Paso's customers. The commenters further allege that a move to 20 pools will cause significant market harm.[91]

Parties assert that tripling the number of pools is an enormous and unprecedented change that greatly impacts existing contracts and the future deliverability of the pools. Commenters cite as an example the last pooling expansion on El Paso's system when El Paso divided the Keystone pool into three smaller pools. As a result of the split, liquidity in the two smallest pools (Plains and Waha) greatly decreased and trading was so de minimis that no monthly index is published for those pools. The parties point out that many of the new pools have few suppliers. They argue that six of the proposed Permian Basin pools would contain four or fewer receipt points[92] and that seven of the new Permian pools would handle a quantity of less than 300,000 Dth/d. They further argue that the Anadarko Dimmitt Pool would effectively have only one supply source because the upstream pipeline cannot physically deliver to El Paso at that point. By reducing the supply choices available in each pool, they argue that El Paso would create a fragmented market that would diminish reliability and price transparency and would give the remaining suppliers more opportunities to exercise market power and command higher prices. The commenters conclude that smaller pools can thus result in decreased reliability and higher costs to consumers.

In data responses, El Paso provided data demonstrating the frequency of constraints at the proposed 20 pools from July 2000 through August 2001. El Paso provided a chart that contains the total number of scheduling cycles where confirmed nominations (FT and IT) exceeded capacity.[93] El Paso explains that "a substantial majority" of those instances were the result of shippers using system-wide receipt point flexibility. El Paso states that if there were specific primary receipt point rights established in the pools, the number of reductions would be "drastically" reduced.

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[90](...continued)
group of El Paso's customers (including CD and FR shippers) filed joint comments on the pooling issues. See Initial Comments on Pooling Issues, filed April 16, 2002, by Conoco, Dynegy, PG&E, Duke Energy, Richardson, Texaco, Williams, Salt River, MGI, Aquila, Coral Energy, and Southern California Generation Coalition.

[91]Initial Comments on Pooling Issues at 2-3.

[92]Initial Comments of Parties on Pooling Issues, at 9 and 10.

[93] El Paso data response filed August 23, 2001, Response to Question No. 4.

Commenters argue that the data supplied by El Paso is flawed and does not justify the proposed 20 pools.[94] They argue that the data include nominations for both FT and IT service and thus do not indicate how much of the pro rata allocations were for firm nominations. They point out that El Paso has inflated the number of pro rata allocations by counting all four cycles of the gas day rather than daily reductions. They state that Permian Basin supply gas was curtailed during the period the data were provided due to the rupture at the Pecos Line just west of the Permian Basin. Also, Permian supply was in unusually high demand at that time due to the unprecedented high price of gas at the California border.

Commenters state that El Paso claims that its pooling proposal is in response to its customers' requests for El Paso to honor their supply rankings. Commenters assert that El Paso's customers would rather stay with the existing six pools, even if El Paso is unable to accommodate their supply rankings, rather than move to 20 pools and have El Paso more able to follow their rankings.[95] Commenters conclude that the Commission should direct El Paso to allocate specific receipt point rights and eliminate systemwide receipt point rights before pursuing such a dramatic change to its pooling structure.

3. Discussion

The Commission has previously found that primary point access by shippers to specific receipt points was necessary to eliminate or greatly reduce routine pro-rata allocation of shipper nominations, thereby improving the reliability of firm service on El Paso's system. Specific rights to receipt points or supply area pooling points may equally accomplish this objective. The Commission agrees with both El Paso and the parties that pooling allows broader access to supply aggregation necessary to accommodate shippers' needs for both competitive prices and supply reliability.[96] The Commission agrees with the parties that pools with few receipt points and small volumes cannot effectively support competitive gas markets. The Commission believes that price transparency and competitive supply markets enhance customers' ability to aggregate and choose supply sources while creating seamless transactions. Fragmented pools can compromise that objective and render the pooling concept useless.

The Commission recognizes that tripling the number of pools on El Paso's system could significantly impact customers and their existing supply contracts. The Commission

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[94]Tr. at 209.

[95]Initial Comments on Pooling Issues at 22.

[96]See Transcontinental Gas Pipeline Corp. 86 FERC ¶ 61,175 at 61,613 (1999).

believes El Paso's pools should encompass a wide enough choice of supply sources to accomplish the objectives of price transparency and liquidity without sacrificing reliability of supply. Once physical pools are established, the Commission has determined that a showing of operational need is necessary prior to allowing modification to pooling areas.[97] The Commission finds that there is sufficient evidence to support El Paso's proposal to increase the number of physical pools in the San Juan Basin from two to four.[98] The data show constraints in the current San Juan pools.[99] It appears that if specific receipt rights are not assigned at the four proposed San Juan pools, daily pro-rata allocations of nominations may be likely to continue.

The Commission finds that there is insufficient evidence of an operational need to expand the Permian and Anadarko pools from four to fourteen. In fact, even El Paso agrees with the parties that no pro-rata allocations were needed for the Permian pool this past winter.[100] The Commission believes that allocating specific primary receipt rights to shippers in the existing Permian and Anadarko pools will resolve the overnomination constraints without compromising liquidity and supply choices. Based on the assertions of El Paso as well as its customers that the capacity allocation process will minimize if not eliminate current supply cuts in the pools, the Commission will reject the proposed changes to the Permian and Anadarko pools at this time, without prejudice to El Paso filing changes to its pooling structure at a future time with the necessary operational support, if circumstances warrant. Consequently, the Commission will authorize El Paso to operate eight pools: Bondad Station, Bondad Mainline, Blanco, Rio Vista, Anadarko, Plains, Keystone, and Waha.

We also believe that El Paso should be able to accommodate the shippers who do not desire flexibility but instead would like certainty at specific receipt points. It does not

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[97]See Nor Am Gas Transmission Co., 85 FERC ¶ 61,039 at 61,118 (1998) reh'g denied, 86 FERC ¶ 61,162 (1999).

[98]El Paso explains that there is a capacity of 675 MMcf/d upstream of Bondad Station but only 575 MMcf/d downstream of the station. Tr. at 213.

[99]Carla Johnson, representing a number of parties regarding pooling issues (Conoco, Dynegy, PG&E, Duke Energy, Richardson, Texaco, Williams Energy Marketing and Trade, MGI, Salt River, Aquila Energy, Coral Energy, and Southern California Generation Coalition) acknowledged constraints at Bondad. Tr. at 216.

[100] Tr. at 216. El Paso maintains, however, that the south system was not operating at capacity last winter, so the system was not tested. El Paso argues that it needs to program to anticipate times when the system is working at capacity.

appear to be inconsistent with the pooling approach used by El Paso to allow shippers to choose specific receipt points as opposed to pools. In fact, El Paso asked shippers to express such an interest.[101] If shippers desire access to only one receipt point upstream of a pool, and are able to contract with a particular source, it appears that El Paso should be able to accommodate such nominations. Therefore, El Paso is directed to make provision in its tariff and service agreements for a shipper to specify a point rather than a pool as a primary receipt point.[102]

E. Summary of Commission Actions

As discussed above, the Commission finds that the current daily allocation of capacity due to the lack of specific receipt point rights is not just and reasonable, and the Commission must act under section 5 of the NGA to direct El Paso to establish specific rights. Further, the Commission finds that continued unlimited growth in demand under the FR contracts does not send proper price signals for expansion of capacity, is not just and reasonable and is not in the public interest, and therefore, directs that the FR contracts be converted to CD contracts with a CD entitlement to be determined by the parties. The Commission also finds that it is unjust and unreasonable for El Paso to collect demand charges for service it cannot provide.

Based on those findings, the Commission directs El Paso to convert the Rate Schedule FT-1 FR contracts to CD contracts with specified maximum daily quantities (MDQs) and to assign receipt point rights utilizing the modified eight pools. The Commission directs El Paso to convert the current FT-1 FR contracts to CD contracts at a CD level to be determined by the parties. If the parties are unable to reach an agreement by July 31, 2002, El Paso must report to the Commission, and the Commission will issue an order to specify how capacity should be allocated on the system.

The Commission will preserve the status quo for small FR customers that take service under the FT-2 rate schedule. These shippers pay a volumetric rate for their service, and their peak loads are currently less than 8,000 Mcf/day. Therefore, these small load customers with minimal receipt rights do not have a significant impact on system use,

[101] August 23, 2001 data response to Question No. 1.

[102] In the allocation process ordered in another section of this order El Paso would only assign an individual receipt point to a shipper after any pro-rata election process assuming that the shippers election was at the closest pool. No additional priority is awarded the shipper because of its more narrow election. However, after the allocation process, the shipper's primary receipt point rights would be at the point only, not the pool.

and continuation of their FR service for the remaining term of the Settlement will not have a negative impact on the remedy adopted in this order. We will require El Paso to establish a service eligibility ceiling quantity for the FT-2 Rate Schedule not to exceed 10,000 Dth/d.[103] Small FR shippers eligible for the FT-2 Rate Schedule may convert to that service in lieu of CD service.

Second, immediately after the initial conversion, but prior to the allocation phase, El Paso is directed to accept requests for turn back of existing contract quantities (from either existing or newly converted contract demand customers) and requests for additional contract quantities from FR customers. El Paso is directed to accept the capacity turnbacks to the extent necessary to satisfy the FR customers' requests for additional service.[104] Any shipper acquiring turnback capacity would assume the corresponding demand charge responsibility. In addition, shippers will have the opportunity to make available for posting permanent or long term release of capacity for either year round use or on a seasonal basis. This may allow summer and winter peakers to match their initial allocation to their individual peak needs.

Third, El Paso will allocate receipt point capacity in the modified eight pools[105] to all existing shippers based on their converted and existing CDs using the iterative process proposed by El Paso in its March 28 proposal.[106] In each round, each CD and converted FR shipper will nominate volumes at one or more pools of its choice, and El Paso will assign capacity on a one-time, pro-rata basis to each shipper at its selected pool. A round will be completed once each shipper has received either its full CD or no capacity remains at the selected pool.[107] No firm shipper is excluded from this process, including those who now have specific receipt point rights. Their existing rights are to be included with all

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[103]See Order No. 636-A at 30,546.

[104]The acceptance of these requests for service will be subject to the creditworthiness provisions.

[105]Individual shippers would be allowed to select individual receipt points if they desire. El Paso will allocate this election by assuming the selection is to the closest pool and include the selection in that pools' pro rata allocation.

[106]This is the same process approved by the Commission in the Topock order.

[107]All shippers, including shippers who have current primary rights, are to participate in the pro-rata allocation.

other rights and allocated pro rata.[108] El Paso will then notify each shipper of the CD amount it received in each pool in the round. A subsequent round will begin with parties nominating any remaining CD amounts to remaining available capacity at available pools. Again, El Paso will assign capacity on a pro-rata basis until each shipper receives its full CD or no capacity remains at the receipt point. After the allocation process, each shipper will have specific receipt rights at individual pools. The aggregate receipt rights at any pool will not exceed the capacity at that pool so that pro-rata cuts should no longer be necessary, absent force majeure.

After completion of the allocation process, El Paso must provide an opportunity for shippers to trade allocations of primary receipt point rights. This will allow shippers again to match supply contracts with receipt points where they are allocated capacity. Further, the Commission will require El Paso to modify its tariff to permit use of secondary receipt points as available. The Commission will further require El Paso to immediately allow the use of its California delivery points as receipt points in order to promote exchanges from off-system deliveries.

El Paso will report the results of the conversion and the capacity rationalization process in a report to the Commission by September 3, 2002. The report should include, by shipper, the initial conversion entitlements, the contract demands after the capacity rationalization process, and the receipt point allocations. The new CD entitlements and receipt point allocations will be effective November 1, 2002.

The capacity allocation will not change the cost allocation of the system, except to the extent a shipper turns back capacity which is acquired by another existing shipper.

In recognition of the Settlement provision that commits El Paso to provide the full requirements of the FR shippers through the term of the Settlement, we will require El Paso to give existing shippers priority for any new capacity that El Paso might propose to construct through the term of the Settlement. Additionally, through the term of the Settlement, we will require El Paso to accept turnback to meet growth in the needs of its existing shippers. At least once a year, El Paso must determine whether any existing shippers require additional CD allocations and to solicit turnback of capacity to meet those additional requests. Any shipper that acquires such turnback capacity would assume the demand charge responsibility for that capacity.

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[108]Other FR shippers and CD shippers have also elected specific rights given the choice.

We will require El Paso to amend its tariff, effective November 1, 2002, to provide for refunds of demand charges to its customers on any day that El Paso is unable to deliver nominated CD volumes from a primary receipt point to a primary delivery point.

The remainder of the Settlement will remain in place (e.g., the Risk Sharing Mechanism, the fuel tracker, etc.). El Paso will continue to be responsible for crediting revenue to customers for the sale of firm capacity to reimburse shippers for the amounts they paid El Paso in the early years of the Settlement under the Risk Sharing Mechanism.

F. Need for an Evidentiary Hearing

Several FR shippers have argued throughout these proceedings that the Commission cannot resolve the capacity allocation issues on El Paso without first holding an on-the-record evidentiary hearing to resolve issues of material fact that they allege are relevant to an evaluation of the issues in these proceedings. Further, several commenters assert that the Commission must hold an evidentiary hearing to provide the parties with an opportunity to obtain through formal discovery operational data to enable them to propose an alternative to El Paso's methodology. In the comments filed in connection with the April 16, 2002 public conference, several parties including the Arizona Corporation Commission, argued that the Commission should hold an evidentiary hearing prior to changing the capacity allocation methodology on El Paso.

APS/Pinnacle list 21 issues of fact that they assert cannot be resolved without a hearing. These include whether El Paso oversold its system, whether there is an implied limitation on the growth that can be added under the FR contracts, whether the amount of growth under those contracts was anticipated, what is the appropriate method of reallocating receipt point rights, whether the assumptions behind El Paso's studies are reasonable, and whether the current capacity issues will be alleviated by a market downturn or other external events prior to the expiration of the Settlement.

Similarly, Southwest Gas argues that the Commission must hold a hearing to determine the exact operational capacity of El Paso, whether any shipper has been curtailed since the issuance of the Commission's decision in Topock, and if so, what injury resulted from the curtailment. In addition, Southwest asserts that a hearing must be held to determine the intent of the parties with regard to FR service under the Settlement, whether the Settlements obligate El Paso to construct additional capacity to meet the needs of its shippers, and whether El Paso unfairly profited from the Settlement. Further, it argues, if an adjustment is made to FR service, there must be an evidentiary hearing to determine whether El Paso should be required to reimburse customers for risk sharing dollars. Southwest Gas also argues in Joint Complainants v. El Paso that the Commission cannot place limitations on the FR contracts without holding an on-the-record hearing under section 7(b) of the NGA to address the existing and future needs of the FR customers and the ability of these captive customers to obtain service in excess of the limitation imposed in their contracts.

On the other hand, Indicated Shippers argue in their post-technical conference reply comments that an evidentiary hearing is not necessary to enable the Commission to prescribe just and reasonable capacity allocation procedures on El Paso.

The Commission finds that an on-the-record trial-type hearing is not necessary to resolve the issues raised in these proceedings. As detailed above, the Commission has adopted just and reasonable procedures to permit the parties to establish reasonable entitlements under the new CD contracts and for allocating the existing capacity on El Paso. If the parties fail to agree on an allocation method, the Commission will establish appropriate entitlements based on current demands; it is not necessary for the Commission to conduct a hearing to determine the precise westward and eastward capacity on El Paso prior to determining a just and reasonable method of allocating existing capacity.

Many of the issues that the parties allege require an evidentiary hearing have been resolved by the Commission as a matter of law or policy. Thus, the Commission has explained that the conversion of FR contracts to CD contracts is consistent with the Commission's duty to protect captive customers from the monopoly power of the pipeline. In addition, the factual issues raised by the parties are either not in dispute or are not material to the Commission's ruling. There is no dispute that there has been significant growth in the takes of the FR customers, that the circumstances on El Paso have changed dramatically since the 1996 Settlement was approved, and that the current capacity allocation methodology on El Paso has resulted in routine pro rata cuts to firm service nominations.

It is not necessary or material to the adoption of a just and reasonable capacity allocation methodology on El Paso for the Commission to determine whether El Paso has oversold its system, whether any shippers have been curtailed since the Commission issued its decision in the Topock proceeding, or whether the economic downturn or other external events might resolve the issues without Commission action prior to the expiration of the Settlement. Neither is it necessary for the Commission to hold a hearing to address alleged inadequacies in the studies submitted by El Paso. The parties have not been hindered in developing alternatives to El Paso's proposal. As set forth on Appendix A, there are a number of proposals before the Commission and many parties presented additional alternatives at the April 16, 2002 public conference. The Commission has properly resolved the relevant issues raised by the parties as legal or policy issues, and a hearing is not required to resolve any disputed issues of material fact.

In TNMA Shippers v. El Paso, the TNMA Shippers filed a motion to require El Paso to respond to initial data requests. El Paso opposed the motion. Consistent with our determination that there are no material issues of fact in dispute that require a hearing, the discovery motion is denied.

The Commission orders:

(A) El Paso's full requirements contracts are converted to contract demand contracts, effective November 1, 2002.

(B) El Paso will file a report with the Commission by August 1, 2002 if the parties cannot agree to entitlement levels, or by September 3, 2002 to detail the results of the capacity rationalization process as directed in this order.

(C) El Paso is directed to modify its Rate Schedule FT-2 to apply only to shippers taking less than 10,000 Dth/d.

(D) El Paso is directed to amend its tariff, effective November 1, 2002, to provide for demand charge credits to its firm customers whenever it is unable to transport nominated volumes for reasons other than force majeure.

(E) El Paso is directed to amend its Order No. 637 compliance filing in this proceeding as directed in this order.

(F) El Paso's capacity allocation proposal is accepted as modified in this order.

(G) Joint Complainants' request for relief in Docket No.RP00–484-000 is granted in part and denied in part as discussed in this order.

(H) TNMA Shippers request for relief in Docket No. RP00-486-000 is granted and denied in part as discussed in this order .

(I) KN Marketing's request for relief in Docket RP00-139-000 is granted in part and denied in part as discussed in this order.

By the Commission.

(S E A L)

Magalie R. Salas,
Secretary.

APPENDIX A

The Capacity Allocation Proposals Before the Commission

While the parties to these proceedings disagree as to the causes and best remedies for the capacity allocation problems on El Paso, all agree that firm customers are not receiving the firm service for which they contracted, and that some changes must be made on the El Paso system. In addition to El Paso, Southwest Gas Corp. (Southwest Gas), Southern California Gas Co. (SoCalGas), and Salt River Project Agricultural Improvement and Power District (Salt River) submitted comprehensive capacity allocation proposals for the El Paso system. Other parties have made suggested modifications to these proposals and counterproposals in their comments. The complaints also propose actions that El Paso should be required to take to resolve the capacity allocation issues. The proposals of the parties are summarized below.

I. El Paso's March 28, 2001 Capacity Allocation Proposal

El Paso's proposal for a new system-wide allocation plan would allocate primary receipt rights for all FT-1 shippers at one or more of 20 pools. Primary receipt rights would be allocated to CD customers equal to their individual CD volumes and to FT-1 FR[109] customers equal to the billing determinants established in the 1996 Settlement. El Paso asserts that the billing determinants are the best proxy for the quantity of capacity rights each FR shipper subscribed to in the 1996 Settlement proceeding. In addition, under El Paso's proposal, FR shippers would have system-wide receipt rights for those volumes above their billing determinants used to serve primary delivery points. These system-wide rights for FR shippers would be scheduled as alternate rights but would be treated in scheduling as having a priority over any other firm contracts using alternate points, and ahead of all interruptible and overrun shippers. In other words, El Paso states, FT-1 FR shippers would have a primary secondary right to schedule all volumes they require above their billing determinant level.

El Paso's proposal would modify the existing scheduling provisions of its tariff and allocate available capacity in the following order: 1) FT-2 Shippers using primary receipt and primary delivery rights; 2) FT-1 FR and CD shippers using primary receipt and primary delivery rights; 3) FT-1 FR shippers using alternate receipt rights and primary

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[109]Rate Schedule FT-2 shippers, i.e., small load customers that pay volumetric rates, would continue to have system-wide receipt rights. El Paso states that the FT-2 shippers' loads are small and assigning each of them very small quantities of primary receipt rights across a wide array of receipt locations would result in a hodgepodge of minimal receipt rights.

delivery rights; 4) FT-1 CD shippers using alternate receipt rights and primary delivery rights; 5) FT-1 FR and CD shippers using primary receipt and alternate delivery rights; 6) FT-1 FR and CD shippers using alternate receipt and alternate delivery rights; 7) IT-1 shippers using grandfathered agreements; 8) IT-1 shippers using first come first served agreements; and 9) authorized overruns.

El Paso states that under its proposal, the amount of available capacity on its system to be allocated among all of its shippers would be determined using the summer flow sheet filed in El Paso's Line 2000 application in Docket Nos. CP00-422-000.[110] El Paso states that summer flow sheets were chosen because they represent the amount of capacity available on a year-round basis due to the impact of ambient temperatures on available capacity. El Paso states that additional capacity made available by lower winter temperatures would be used to offset maintenance outages to the benefit of shippers using primary firm capacity rights or, if not needed for that purpose, would be available to be used on an alternate firm basis or sold on an interruptible basis.

El Paso states that, consistent with the methodology used in allocating capacity at Topock, Arizona,[111] shippers would be permitted to elect receipt right preferences for allocating contract rights. El Paso would use a scheduling model to perform the allocation calculations. Shippers with receipt rights in a single basin would be allocated primary receipt rights pro rata among the pooling areas within that basin in proportion to each pooling area's design receipt capacity. All other shippers would be asked to provide to El Paso elections that specify receipt pools where primary rights are desired, the quantity of rights desired at those locations, and the locations to which those receipt rights are to be delivered. El Paso states that when all the elections have been received, they would be processed using the scheduling model to determine where elections exceed available capacity. All elections that exceed the available capacity at a particular location would be allocated pro rata using the current tariff provisions. El Paso states that after processing is complete, each shipper would be notified what portion of its election was successfully allocated. The shipper would then make an election among the remaining pooling areas in amounts not to exceed its unallocated capacity receipt rights. Any receipt capacity allocated to a shipper in an earlier round could not be reduced by the elections of shippers in later rounds. El Paso states that this multi-step, iterative process of elections and allocations would be repeated until each shipper's defined volumetric entitlement (full billing determinants or CD) was assigned to primary receipt locations.

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[110] 95 FERC ¶ 61,176 (2001). El Paso states that the north mainline capacity is shown on flow sheet FERC 1042. The south mainline capacity is shown in the Line 2000 filing.

[111] El Paso Natural Gas Co., 93 FERC ¶ 61,060 (2000).

El Paso does not propose to establish contract path rights on its system. El Paso states that there are currently 106 delivery points covered by FR agreements, and, as a result, the distribution of El Paso's delivery obligation changes daily. El Paso states that it cannot establish contract path rights on its system as long as the volumetric rights of shippers are not clearly specified.

El Paso asserts that its proposal will provide shippers with a greater degree of certainty in the scheduling process. However, El Paso states that there may be occasions when the distribution of the FR shippers' loads or a lack of displacement transactions will require El Paso to allocate capacity pro rata consistent with its tariff.

As stated above, El Paso submitted additional information and studies on its proposal in conjunction with the technical conference. Specifically, El Paso prepared several studies in response to requests made at the July 18-19, 2001 technical conferences. Each study allocates system receipt and delivery point capacity using the capacity allocation proposal filed by El Paso on March 28, 2001, but using varying assumptions. To simulate the allocation process, El Paso asked each FT-1 shipper to provide its supply preferences by ranking the proposed 20 pooling areas by order of desirability. If a shipper did not indicate a preference, El Paso used a default ranking. In each of the studies, El Paso allocated receipt point capacity up to the full contract demand for each current CD customer. The methodology used to allocate capacity to FR shippers varied from study to study.

In Study 1, El Paso allocated capacity to FR shippers based on non-coincident peak day demands, i.e., each customer's individual peak demand, during the test period for the Docket No. RP95-363-000 rate case. Study 1B allocated capacity based on coincident peak day demands, i.e., the system peak day, during the test period for the Docket No. RP95-363-000 rate case. Study 2 allocated capacity based on billing determinants agreed to in the 1996 Settlement. Study 3 allocated capacity based on non-coincident peak during the most recent 12 calendar months (July 2000 to June 2001). Study 3B allocated capacity based on coincident peak (i.e., system peak) during the same 12 month period. Study 4A based allocations on projected demand through the end of the Settlement (2005) regardless of whether the peak demand for such customer occurs in the winter or summer. Study 4B based allocations on projected demand based on the greater of the aggregate projected demand for the FR shippers reflected in Study 4A. Because the projections received by El Paso showed an aggregate winter load that was greater than the aggregate summer load, Study 4A was based on the projected winter loads for the FR customers.

In response to requests made at the August technical conference, El Paso submitted four additional studies. Study 5A based allocations to FR shippers on Winter 2000-2001 non-coincident peak demands. Study 5B was based on Summer 2000-2001 non-coincident peak demands. Study 6A was based on the average of the last five winter seasons' non-coincident peak demands. Study 6B was based on the average of the last five summer seasons' non-coincident peak.

In addition, El Paso proposes to increase the number of pools from the current six pools to twenty pools, and shippers would elect as their primary receipt points one or more of these twenty identified pooling areas. El Paso states that it established the boundaries for its proposed pooling areas by analyzing supply areas on its system and determining which receipt points could be grouped together as having similar operational characteristics. El Paso states that it believes that it has arrived at the right number of pooling areas to maximize shippers' flexibility in sourcing gas while working with the pipeline's configuration and its operational realities to provide more certainty in transportation services.

El Paso states that it selected the use of pooling areas rather than individual receipt points for several reasons. First, El Paso states, use of all 141 individual receipt points on the system would result in shippers holding small and often impractical volumes of receipt rights. Second, El Paso states, it determined that using 20 pools instead of the current six, would enable El Paso to more closely follow the priorities set by the pooling entities. Finally, El Paso states, because the 20 pools are based on potential constraint points on the system, El Paso believes that using these pooling areas will reduce the number of shippers affected by individual physical constraints on the pipeline. El Paso states that to the extent that a constraint does occur within a pooling area, only those shippers with receipt point capacity in the pooling area where the constraint occurs would be affected.

Comments on El Paso's proposal were filed by a number of parties.[112] Generally, the FR customers, i.e., the EOC Shippers,[113] APS/Pinnacle, El Paso Electric, Salt River,

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[112]Comments were filed by Aquila Energy Marketing Corporation (Aquila), The Arizona Corporation Commission (Arizona Commission), Arizona Public Service and Pinnacle West Energy Corporation (APS/Pinnacle), the CPUC, Duke Energy Trading and Marketing (DETM), East of California (EOC) Shippers, Enron North America Corp. (Enron), Indicated Shippers, MGI Supply Ltd. (MGI), the Public Utilities Commission of Nebraska (Nebraska PUC), jointly by Sid Richardson Energy Services Co., Sid Richardson Pipeline, LTD., Sid Richardson Energy Marketing, LTD (collectively Richardson), PG&E, Salt River, Southern California Gas Co. (SoCalGas), Southwest Gas, and Williams Energy Marketing & Trading Co.

[113]EOC Shippers are Apache Nitrogen Products, Inc., Arizona Electric Power Cooperative, ASARCO, Inc., BHP Cooper, Inc., Arizona Gas Division of Citizens
(continued...)

Richardson and Southwest Gas, and the Arizona Commission oppose El Paso's proposal to allocate capacity based on billing determinants. The CD customers, on the other hand, generally support allocating capacity to FR shippers based on billing determinants but object to the priority given to FR shippers in scheduling volumes above the billing determinants level. The comments of the parties are discussed in more detail below.

II. Alternate Proposals

Several parties offered alternative proposals in their post-technical conference comments. In addition, on November 13, 2001, Salt River filed a comprehensive capacity allocation proposal referred to as the "Strawman Proposal." Comments on the Strawman proposal were filed on December 7, 2001.

Southwest Gas, El Paso's largest FR customer, proposes to convert FR customers to contract demand service and permit FR customers to establish contract demands above their respective billing determinant levels by receiving an allocated share of the Line 2000 capacity (230,000 Mcf/d) and an allocated share of the Line 2000 Power-Up capacity (320,000 Mcf/d). The allocation of the Line 2000 capacity among the FR customers would be based upon cost levels that these FR customers have borne and continue to bear under the 10-year Settlement. Southwest Gas further proposes to cover the costs of the project through a surcharge to be imposed on the FR customers to recover the cost of service associated with the Power-Up capacity, as well as a base transportation charge. Southwest Gas' proposal includes a one-time trading procedure of monthly and seasonal capacity rights among converting FR customers.

Under Southwest Gas' proposal, receipt capacity would be allocated to FR shippers based upon their non-coincident peak quantities using data from the most recent twelve-month period. Receipt capacity for the CD customers would still be based on their CDs. Capacity would then be allocated based on the ratio of a shipper's individual CD or noncoincident peak to the sum of all CD and noncoincident peak quantities. Both CD and FR shippers desiring to nominate above their allocated receipt capacity would have to nominate the excess in a second round of nominations.

El Paso Electric proposes that El Paso be required to hold a special open season for FR shippers prior to allocating receipt capacity. Under this special open season, the CD

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[113](...continued)
Communication Company, El Paso Electric Company, El Paso Municipal Customer Group, Phelps Dodge Corporation, PNM Gas Services, a division of Public Service Company of New Mexico, and Southern Union Gas Company.

shippers would be able to turn back capacity they no longer wish to hold, or simply release any excess capacity for a finite period of time. Only FR shippers would be permitted to bid for this capacity. Agreement reached tentatively in the open season bidding would be contingent on a FR shipper's willingness to convert its FR contract to a CD contract. If a FR shipper can acquire sufficient capacity either through turnback or release, then these shippers have the option to convert to a CD contract. This opportunity to convert status would be completely optional. Other proposals suggest capacity allocation on the average of the last five years non-coincident peak or on the basis of the higher of coincident peak for the past twelve months or billing determinants.

On November 13, 2001, Salt River filed its proposal. Salt River states that under its proposal, CD customers would retain their current CDs, while FR shippers would convert to seasonal entitlements based upon their historic reliance on the system, but weighted toward present use.[114] Under the proposal, Line 2000 capacity would be required to be brought into service promptly by El Paso, and El Paso would be directed to solicit turned-back capacity to meet shortfalls in firm requirements. The proposal provides for reservation charge credits for firm volumes not shipped. In addition, the proposal would allow shippers to segment their capacity on the Northern and Southern mainlines. The proposal would reduce the number of pools to two. A number of comments were filed on Salt River's proposal.[115]

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[114]FR customers would be required to convert to seasonal CD service with entitlements based on historical non-coincident peak, weighted to reflect current usage. Salt River used historical data from El Paso's studies (Studies 5a, 5b, 6a and 6b) for the 5-year period 1995 to 2000 to calculate each FR shipper's average quantities. For CD customers, Salt River used the current CD (July 2001) in the calculations. In the allocation mechanism the 5-year average non-coincident peak and the 2000 non-coincident peak for FR shippers were averaged, for the summer and winter, respectively, thereby weighting the conversion quantity to the current period. The 5-year average was given the same weight in the calculation as the 2000 non-coincident peak, i.e., the most recent year was given the same weight as the average of the last five years combined.

[115]Comments Salt River's proposal were filed on December 5, 2001, by Arizona Commission, AEPCO,Citizens Communications, APS/Pinnacle, California Parties (California Parties are SoCalGas, San Diego Gas and Electric Co. and the CPUC), Conoco, DETM, Panda Gila, El Paso, El Paso Electric, El Paso Municipals Customer Group (EPMCG), Indicated Shippers, MGI, Oneok Energy Marketing and Trading Co., L.P. (Oneok), PG&E Energy Trading-Gas Corporation (PG&E ET-Gas), PG&E, Phelps Dodge Corporation (Phelps Dodge), Public Service Company of New Mexico (PNM), Public Utilities Commission of Nevada (PUCN), Richardson, Southern California Edison

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III. Joint Complainants v. El Paso

On July 13, 2001, in Docket No. RP01-484-000, Joint Complainants,[116] a group of El Paso CD customers and the CPUC, filed a complaint challenging El Paso's capacity allocation procedures. These parties argue that El Paso has sold more firm capacity on its system than it can reliably provide, resulting in a violation of the pipeline's public service obligations and of its obligations under the 1996 Settlement. Joint Complainants assert that this alleged overselling of firm capacity, combined with the unlimited growth of the demands by the FR customers, results in unjust, unreasonable and unduly discriminatory services on the El Paso system, in violation of sections 5 and 7 of the NGA, as well as the Commission's regulations, the 1996 Settlement, and relevant principles of contract law which limit full requirements to reasonable levels.

Joint Complainants ask the Commission to provide a three-part remedy to resolve these violations. First, they ask the Commission to convert the FR contracts to CD contracts at a reasonable CD level. Joint Complainants assert that if FR demand by EOC shippers is permitted to continue to grow without limits there will be further erosion of firm service provided to El Paso's CD customers. Joint Complainants assert that a reasonable CD level would be a level equivalent to each shipper's billing determinant, or, for a transition period, 110 percent of the billing determinant level. Alternatively, Joint Complainants state that each FR shipper should be given the opportunity to utilize a seasonal CD entitlement that, on an annual average basis, would equal its billing determinant.

Second, Joint Complainants ask the Commission to order El Paso to expand its system to the extent necessary to enable it to meet its existing firm transportation obligations. Third, Joint Complainants ask the Commission to require El Paso to pay demand charge credits for firm volumes it does not transport for reasons other than force majeure.

El Paso filed an answer to the complaint. In addition, Texas, New Mexico, and Arizona Shippers (TNMA Shippers) and APS/Pinnacle filed comments in opposition to the complaint. Comments supportive of the complaint were filed by Midwest United Energy,

[115](...continued)
Company (SoCalEd), Southern Union Gas Company (Southern Union) and Southwest Gas.

[116]Joint Complainants are Aera, Amoco, BP, Burlington, Conoco, Coral Energy, ONEOK, PG&E, Panda Gila, CPUC, SoCalEdison, SoCalGas, and Texaco.

L.L.C., Enron and Richardson. Southwest Gas filed comments in response to Enron's comments.[117] The arguments of the parties are discussed below.

IV. Texas, New Mexico and Arizona Shippers v. El Paso

On July 17, 2001, in Docket No. RP01-486-000, the Texas, New Mexico and Arizona Shippers[118] (TNMA Shippers) filed a complaint alleging that El Paso violated the Natural Gas Act (NGA) and breached its contractual obligations to its customers by failing to maintain its facilities in a manner that will allow it to provide firm service up to certificated levels. The TNMA Shippers argue that El Paso has a legal obligation under Section 7 of the NGA and Paragraph 16.3 of the 1996 Settlement to maintain system capacity sufficient to meet all of its contractual commitments to provide firm transportation service. TNMA Shippers request that the Commission direct El Paso to show cause why it should not be required to augment the capacity available for transporting current customers' entitlements by dedicating the southbound capacity of its new Daggett-Ehrenberg line in California and the added capacity recently proposed for its Line 2000 for use by its existing firm transportation customers rather than for new customers.

El Paso filed an answer to the Complaint. In addition, ONEOK, Indicated Shippers, SoCalGas, Richardson, and SoCalEdison filed comments on the complaint,[119] and timely motions to intervene were filed by many of the parties participating in the capacity

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[117]In addition, timely motions to intervene were filed by Aquila, Arizona Corporation Commission; AEPCO; Citizens Communications; Asarco and BHP; Dynegy Marketing and Trade (Dynegy); El Paso Electric; EPMCG; MGI; PG&E National Energy Group Companies; Phelps Dodge and Apache.; Phillips Petroleum Co. and Phillips Gas Marketing Co. (Phillips); PPL Energy Plus (PPL); New Mexico PSC; Nevada PUC; Saguaro Power Company (Saguaro); Southern Union; and Williams. Motions to intervene out of time were filed by Calpine Corporation (Calpine); DETM; Nevada Attorney General's Bureau of Consumer Protection; and Southern California Generation Coalition and Individual Members.

[118]The Texas, New Mexico and Arizona Shippers are Apache, AEPCO, Citizens Communications, BHP, El Paso Electric, EPMCG, Phelps Dodge, New Mexico PSC, Salt River, and Southern Union. For the most part, these shippers are full requirement customers located in Arizona, New Mexico, and Texas.

[119]Indicated Shippers filed separate motions to intervene in this proceeding.

allocation proceeding.[120] The Nevada Attorney General's Bureau of Consumer Protection and the Southern California Generation Coalition filed untimely motions to intervene. The arguments of the parties are discussed below.

V. KN Marketing v. El Paso

On December 16, 1999, KN Marketing (now ONEOK Energy Marketing and Trading Co., L.P.) filed a complaint with the Commission alleging that El Paso's allocation of firm mainline capacity on the east end of its system, i.e. the San Juan Basin to Texas, is unjust and unreasonable because El Paso sells firm capacity in excess of the available capacity. KN Marketing asked the Commission to order El Paso to refund all demand dollars KN Marketing has paid with respect to allocations that were not excused by force majeure in the East End. El Paso filed an answer to the complaint asserting that it has not oversold its system and that it has allocated its capacity consistent with its tariff, its contracts and the applicable Settlements.

As stated above, in its order in Amoco Energy Trading Company v. El Paso Natural Gas Co.,[121] the Commission held the issues raised in the KN complaint in abeyance pending examination of system-wide capacity allocation issues in El Paso's Order No. 637 proceeding.

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[120] Aera, Amoco and BP, Aquila, Arizona Corporation Commission, APS/Pinnacle, ASARCO, Burlington, Calpine, Conoco, Coral Energy, DETM, Dynegy, El Paso Merchant Energy, L.P. (El Paso Merchant), Enron, Exxon Mobil Corporation (Exxon), MGI, Midwest United Energy L.L.C. (Midwest Energy), Nevada Attorney General's Bureau of Consumer Protection, Oneok, PG&E, PG&E National Energy Group Companies, Phillips, PPL, CPUC, Saguaro, Richardson, SoCalEdison, SoCalGas, Southern California Generation Coalition, Southwest Gas, Texaco and Williams.

Timely, unopposed motions to intervene are granted by operation of Rule 214 of the Commission's Rules of Practice and Procedure. 18 CFR 385.214 (2001).

[121] 93 FERC ¶ 61,060 (2000), order on clarification, 93 FERC ¶ 61,222 (2000), order on reh'g, 94 FERC ¶ 61,225 (2001).

APPENDIX B

Summary of Comments Submitted Regarding the April 16th, 2002 Public Conference

On April 16, 2002, a public conference was held to receive feedback from all parties regarding alternatives to El Paso's capacity allocation proposal. In addition to the presentations made at the conference and recorded in the transcript, comments and reply comments were filed. As discussed in detail below, most CD shippers are generally in favor of converting FR service to CD service but request prompt action. The FR shippers oppose conversion and object to the proposed entitlements under the new CD contracts. Most of the parties oppose El Paso's proposal to increase the number of pools from 6 to 20.

FR Conversion

El Paso generally supports converting FR service to CD service and believes that use of system peak (the higher of December 12, 2002 coincidental peak demand or the 1996 Settlement billing determinants) is supported by the changed circumstances on El Paso's system. El Paso states that the allocation among FR shippers could be resolved at the negotiating table if the Commission institutes a capacity allocation mechanism. El Paso also is willing to assign rights at individual receipt points, agrees that the 1996 settlement should be kept intact to the maximum extent possible, and supports maintaining the FT-2 rate schedule. El Paso offers to implement a capacity rationalization process (accepting turn back capacity to meet requests for increased capacity) and to "sculpt" or allow shippers to establish seasonal contract demands. Any remaining capacity requests could be met by the Power Up project which would add compression to its Line 2000 project and increase capacity by 320,000 Mcf/d. El Paso is willing to forego cost recovery for the above mentioned system expansion until the next rate case if it receives a presumption for rolled-in rate treatment and commitments from its shippers not to challenge the prudence of the project in the next rate case.

OEMT, PG&E, PUCN, and Panda suggest that the Commission promptly order the conversion of FR contracts to CD contracts to restore certainty of flow for nominated firm service. Indicated Shippers, SoCalGas, Dynegy, and SCGC recommend capacity allocation changes as a necessary first step to pathing the system. Indicated Shippers state that the Commission should exercise its Section 5 authority to impose a reasonable limit on the demands of the FR shippers to convert their FR contracts to a defined quantity. CPUC and SoCalEd argue that allowing some FR shippers to take more service than they pay for is discriminatory and would shift costs to other customers resulting in some customers receiving less than what they pay for and others receiving more than they pay for. PUCN argues that existing CD customers should not be placed at a disadvantage to new CD customers in the allocation of capacity rights. SoCalEd argues that FR shippers should be converted to CD service at their BD level, or El Paso needs to build additional facilities.

The FR shippers,[122] CPUC, Indicated Shippers, SoCalGas, SoCalEd, Southwest Gas and El Paso Electric believe there is insufficient capacity to meet core customer needs. All of these parties believe El Paso has violated the settlement by not providing new facilities to meet the needs of its customers. They assert that limiting full requirements service would result in a significant, adverse financial impact on the Southwestern economy as a whole. Southwest Gas states changes in capacity allocation constitute contract abrogation and would result in severe shortfall in service to its residential customers because it is not based on non-coincidental peak requirements. Arizona Corporation Commission argues a change in capacity allocation would be harmful to the citizens of Arizona. For example, reallocating pipeline capacity would reduce access to pipeline capacity, thereby depriving Arizona of the essential supplies of natural gas needed to generate electricity used to heat and cool homes and fuel industries during peak periods. In addition, any change in capacity allocation must acknowledge Arizona's growth in population and energy use. Arizona customers are captive geographically and contractually to El Paso who is the only pipeline that serves the middle and southern portion of the state.

The FR shippers assert it is the Commission's most basic responsibility to protect captive customers from the exercise of market power. They argue that, given the removal of the price cap on capacity release, the releasing shippers are in a position to extort very high prices from all of the shippers desperate to meet their service needs without having alternative options and that shippers will be forced to purchase peak demand service at spot market clearing prices. The FR shippers point out that any pipeline capacity that is released will be available to all shippers, whether former FR shippers or others, so the former FR customers will have to outbid the merchant plants for pipeline capacity.

SCGC, PG&E, El Paso Electric, and Southwest Gas state seasonal needs should be used as a basis to establish firm capacity rights of FR shippers. The FR shippers state that the selection of a single date as a basis for assigning pipeline capacity rights is by nature arbitrary and likely understates actual usage due to the cuts that El Paso has had on its system. EOC states that human needs and critical customers are being ignored because the use of coincident peak and scheduled volumes is discriminatory. EOC shippers argue that the BDs cannot reflect entitlement since they merely were numbers used to allocate cost in the last rate case.

OEMT and Panda believe capacity rights should be rationalized and that El Paso should solicit capacity turn-backs from CD shippers. The FR shippers propose that all firm shippers on the system, both CD and FR, should specify the firm contract demand level of

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[122]Salt River Project, PNM, Phelps Dodge, EPMCG, Arizona Corporation Commission, Citizens Communications, APS/Pinnacle, and Southern Union.

capacity to which they are willing to commit. This election shall be binding and made within 6 months of FERC approval of settlement methodology. Second, any existing CD customer may reduce its current firm service capacity commitment on the El Paso system within 60 days, without penalty or exit fees. Any FR shipper may elect to terminate its agreement within 60 days, without penalty or exit fee. Third, all contract commitments from FR shippers committing to a specific CD level shall be for a term not less than 10 years. Any current CD customer proposing an increase in its firm capacity rights shall commit to a contract term of not less than 10 years for all of their contracted capacity. Fourth, seasonality and voluntary capacity turnback should be pursued. Fifth, FR shippers believe adding pipeline capacity via additional compression would help alleviate capacity constraints.

CPUC contends that California shippers cannot turn back capacity without a formal hearing authorizing service abandonment. However, if turnback capacity is allowed at the California border, CPUC contends the California shippers should have the first option to that turnback capacity. Finally, CPUC argues that if turnback capacity becomes available, FR service should not include the ability to provide electric power generation service back into California, which is above and beyond their specific customer needs. Conversely, SCGC believes capacity turnbacks would help provide relief by making scarce capacity available for more efficient use.

OEMT suggests that if the capacity turnback process is inadequate to meet all needs, El Paso should be required to construct additional capacity. El Paso Electric calls for El Paso to dedicate its Line 2000 to FR shippers and to build more facilities to meet the growing firm shipper demands. Southwest Gas recommends that: (1) El Paso be required to construct the Power-up capacity and allowed to recover its cost of operating that capacity through an incremental rate; (2) Power-up capacity be allocated among FR customers based upon a percentage of BDs or December 12, 2001 coincidental peak throughput; and (3) primary contract holders be allowed to trade seasonal or monthly rights as part of a negotiating or iterative nomination process. Finally, Southwest Gas states that if the Commission eliminates FR service, it must permit those customers to schedule their new contract demand transportation to delivery zones (i.e., by defining their mainline contract quantities on a zonal basis, not on the basis of existing scheduling delivery points).

Indicated Shippers, SoCalEd, SoCalGas, PG&E, and SCGC state that demand charge credits should be mandated for shippers that do not receive the FT capacity for which they have paid. Demand charge credits would give El Paso an incentive to expand its system to meet contractual obligations and a disincentive to sell additional FT service when it cannot meet its current FT obligations.

EPMCG shippers, who take service under Rate Schedule FT-2, support maintaining the status quo for FT-2 shippers. Indicated Shippers believe there should be some limitations to FT-2 service to provide certainty because their recent usage is nearly double their BDs.

PG&E and FR shippers suggest that the California delivery points should also be available as receipt points at which exchanges or backhauls from storage facilities or other pipeline systems could be more readily accommodated. Southwest Gas and FR shippers asks that El Paso be required to offer firm backhaul transportation from California points under existing transportation agreements. Indicated Shippers state that FR shippers should not be permitted to release capacity above their BDs.

Timing

Indicated Shippers and SCGC claim substantial financial harm because of El Paso's cuts in CD firm nominations. For the three-year period from 1999 through 2001, Indicated Shippers claim these cuts, as set forth in affidavits attached to their comments, have resulted in nearly $103 million losses of five types: (1) stranded demand charges and surcharges; (2) sellers' lost revenues; (3) buyers' increased costs; (4) additional manpower costs; and (5) other unquantifiable miscellaneous injuries. OEMT suggests that the Commission should act promptly on the damages pertaining to El Paso's failure to meet its firm service obligations to OEMT. SoCalEd and PG&E suggest that the Commission redress El Paso's past certificate and contractual violations. EOC shippers state that Indicated Shippers' calculations of financial harm do not consider the materially-increased profits that the shippers may have been able to achieve as a direct result of the shortages caused by El Paso's actions.

FR shippers agree that El Paso should undertake the necessary steps for system expansion. FR shippers state that El Paso should determine a reasonable timetable and designate a date by which all firm capacity commitments will receive full service. EOC shippers strongly urge that there be an opportunity for discovery through settlement, or alternatively a hearing, protected by confidentiality through which serious settlement or hearing discussions could occur.

FR shippers assert significant lead time for any remedy is needed to avoid operational chaos and to allow for finding some other way to get the same needed supply. CD shippers are concerned that the process may lag because FR shippers have an incentive to delay the capacity allocation process. EOC shippers suggest that before a settlement can be achieved, the Commission needs to establish the actual operational capacity on El Paso system and must determine whether El Paso has failed to meet its service obligations under the Natural Gas Act. El Paso replies that EOC shippers's are essentially announcing that they have no intention to be part of any cooperative resolution to the capacity allocation issues. SoCalEd suggests that a new rate case to address all of the issues is necessary. SoCalGas suggests that an audit team consisting of members of the Commission Staff and representatives of CD and FT-1 FR shippers be directed to audit nominations by FT-1 FR shippers from January 1, 2000, to the present.

El Paso Electric states that if the Commission cannot adopt other FR shipper proposed remedies, the existing settlement should be dissolved and a new rate case filing should be ordered. As part of a new rate case, El Paso Electric suggests an open season where FR shippers determine their needed CD capacity on a seasonal basis and capacity turnback would take place. In the alternative, El Paso Electric recommends awarding FR customers a quantity up to the midpoint between their BD quantity and their NCP quantity on a seasonal basis. PNM, El Paso Electric, and Southwest Gas suggest the Commission issue an order clarifying the outstanding legal and factual issues and setting the matter for hearing.

Pooling

Companies[123] argue that the Commission should reject El Paso's proposal to move to twenty pools. Companies contend El Paso's pooling proposal to increase the number of pooling points from 6 to 20: (1) reduces and restricts liquidity; (2) limits shipper flexibility to purchase gas, with no increased benefits; (3) would not reduce the number of transportation cuts on the El Paso system; (4) is counter to the goal of certainty of flow for firm service on El Paso; (5) reduces the number of buyers and sellers in each pool; and (6) creates fewer and incomplete pricing mechanisms. Companies also argue that allocating system capacity alleviates El Paso's stated need to create 20 pools. Further, OEMT contends that El Paso's proposal relies on receipt point capacity where little or no physical ability to receive gas exists. OEMT suggests that the Commission should establish contract paths on the system to facilitate capacity release as envisioned by Order Nos. 636 and 637.

Companies suggest that El Paso be required to allocate receipt rights among only the current six pools, which would resolve the bulk of the allocation problems on El Paso's

[123]The following companies include producers, local distribution companies, gatherers, end users, generators, and marketers, and also include both CD and FR customers: PG&E; DETM; Aquila; Coral Energy; Dynegy Marketing and Trade; Conoco; Texaco; Salt River Project; Energy Advocates LLP; MGI; Williams Energy Marketing & Trading Company; Southern California Generation Coalition; Richardson; SoCalGas; Indicated Shippers; Southern California Generation Coalition; Southwest Gas; and ONEOK.

system without negatively impacting gas competition. Panda Gila states that the proposal to increase the number of production area pools from 6 to 20 should be deferred, pending the outcome of other changes on the El Paso system (i.e., elimination of the FR contract status and assignment of specific pool rights).

APPENDIX C

Summary of Affidavits Submitted by Contract Demand Customers

In Docket No. RP01-484-000, Joint Complainants filed copies of affidavits of Penny Barry of BP Energy Company (formerly Amoco Energy Trading Co.), Robert Eason of Burlington Resources Oil & Gas Company, Nicholas Rassinier of Conoco, Inc., and Donald Lindquist of Texaco Natural Gas Inc. that had been previously filed in the proceeding in Amoco Energy Trading v. El Paso Natural Gas, Docket No. RP99-507-000, to show financial harm. Joint Complainants filed a second set of more recent affidavits on behalf of BP Energy, Burlington, Conoco, ONEOK, and Texaco to show that this harm has continued since the filing of the earlier affidavits. The affidavits set forth the level of cuts that these CD shippers have experienced on El Paso.

In its comments submitted at the public conference on April 16, 2002, Indicated Shippers provided additional updated information in affidavits attesting to the financial harm suffered by BP Energy, Burlington, Coral Energy and Aera, Occidental Energy Marketing Inc. (OEMI), and Texaco for the period from January 1, 1999 to December 31, 2001. The affidavits allege five types of financial harm, i.e., stranded demand charges, lost marketing revenues, increased costs associated with finding replacement supplies, additional manpower costs, and other miscellaneous costs, such as loss of contracts and missed marketing opportunities.

Finally, in response to a May 8, 2002 data request, additional documentation was filed by Indicated Shippers and SoCalGas.

The affidavit and additional documentation are summarized below by company.

BP Energy

The initial affidavit submitted for BP Energy (formerly Amoco Energy Trading Co.) in Docket No. RP99-507-000 states that at the time of the filing of the complaint in that proceeding, Amoco and Burlington had experienced cuts in Cycle 1 nominations as high as 57 percent at Topock. For the month of August 2000, Amoco's cuts for that delivery point averaged 48 percent, and cuts for gas nominated from San Juan to the east end averaged 33 percent. The affidavit states that financial harm to Amoco grew from $1 to $2 million annually to more than $6 million since KN's complaint filed against El Paso on December 16, 1999.

The second affidavit submitted on behalf of BP Energy states that it continues to experience significant cuts in its seven transportation contracts with El Paso for firm transportation service from San Juan, Permian and Anadarko basins to SoCalGas/Topock, Mojave/Topock, PG&E/Topock and SoCalGas/Ehrenberg. Cuts for the period January 1, 2001 through June 30, 2001 averaged approximately 16% or 18,000 Dth/d, which in turn resulted in stranded demand dollars of $299,000 for BP Energy and another $414,000 for the contracts under which BP Energy ships or manages as agent. In addition to these stranded demand costs, BP Energy states that it suffers financial harm consisting of lost revenues from being forced to find other less attractive markets for its production, or having to curtail production due to lack of alternative markets.

The affidavit submitted at the public conference on behalf of BP asserts that for the period January 1, 1999 through December 31, 2001, Cycle 4 cuts were 40,063,202 MMBtu. This is gas that BP nominated on El Paso, for which demand charges were paid, and El Paso was unable to deliver at primary delivery points. The affidavit further states that the total stranded demand charges related to CD volumes that were not scheduled were $10,132,998. Total lost revenues for BP associated with having to find other markets for gas (i.e., the difference between actual sales price to those other markets and the first of the month cost of gas plus any additional transport costs for moving to alternate markets) were $28,989,212. There were additional manpower costs and miscellaneous costs and harm associated with these cuts, such as missed opportunities.

Burlington

In the initial affidavit Burlington states that for the summer months of 2000, cuts under Contract No. 97YG (into SoCalGas/Topock) peaked at 66% in June, 58% in July and 58% in August. Cuts under Contract 97YW (SoCalGas/Ehrenberg) peaked at 45% in June, 47% in July and 47% in August. Cuts under Contract No. 97J4 (into Waha and other points on the east end of El Paso's system) peaked at 45% in June, 41% in July and 51% in August. Burlington states these cuts have caused significant financial harm, but offers no cost data in support.

The second affidavit submitted on behalf of Burlington states that for the three-month period since the reallocation of delivery rights at the SoCalGas/Topock delivery point effective April 1, 2001, nomination cuts for Burlington of gas sourced from San Juan under Contract No. 9M7Z averaged 26%, and nomination cuts of gas sourced from Waha averaged 5%. Nomination cuts of gas sourced from San Juan under Contract No. 97YW averaged 35%, nomination cuts of gas sourced from Waha averaged 5%, and nomination cuts of gas sourced from San Juan under Contract No. 97J4 averaged 10%. The affidavit further states that Burlington Resources' overall San Juan basin cuts over this period averaged 21%.

The affidavit submitted at the public conference on behalf of Burlington states that for the period January 1, 1999 through December 31, 2001 Burlington incurred cycle 1 cuts in excess of 150 Bcf, cycle 4 cuts in excess of 145 Bcf, and total stranded demand charges of $17,964,434.

Conoco

In the initial affidavit Conoco states that for the time period from May 1, 2000, through August 18, 2000, the cycle 4 scheduling cuts for Conoco's firm transportation contract with El Paso (9DWE back-haul firm Havasu transport) were 14% for May, 26% for June, 27% for July and 37% for the first 18 days in August. Similar to Burlington, Conoco states these cuts have caused significant financial harm, but offers no supporting cost data.

The second affidavit submitted on behalf of Conoco states that for the time period March 1, 2001 through June 30, 2001, the cycle 4 scheduling cuts under Conoco's Contract No. 9DWE were 37% for March, 40% for April, 10% for May and 15% for June.

Texaco

In its initial affidavit Texaco states that it has been cut since July 2000 an average of 50,000 to 60,000 MMBtu/d on Cycle 1 nominations for its 179,000 MMBtu/d of firm transportation on El Paso's system, with a delivery point at Topock, allowing for deliveries into Mojave, PG&E, and Southwest Gas. This represents a 34% cut of its firm transportation. Cycle 2 nominations have been cut by an average of 20,000 MMBtu/d. It was cut 12,500 MMBtu/d in July 2000 and 18,800 MMBtu/d in August 2000, resulting in financial harm of $350,000 in transportation demand costs. In addition, it has had to utilize 4 nomination cycles in order to flow as much transportation as possible, and purchase Permian gas at a premium price on cycles 2 and 3, resulting in additional costs of millions of dollars to Texaco and its affiliates. Two of Texaco's long-time fuel suppliers have notified it that they will no longer sell natural gas to Texaco because it is an unreliable buyer, unable to flow gas on a consistent basis.

The second affidavit submitted on behalf of Texaco states that between January 1, 2001, and July 9, 2001, Texaco incurred $1 million in stranded transportation demand costs, which does not include the cost to buy more expensive gas at the California border to cover the gas that did not flow. The average daily stranded firm transportation was as follows: 2,248 MMBtu/d in January; 5,002 MMBtu/d in February; 13,534 MMBtu/d in March; 18,239 MMBtu/d in April; 35,580 MMBtu/d in May; 20,384 MMBtu/d in June; and 18,096 MMBtu/d from July 1-9.

The affidavit submitted at the public conference on behalf of Texaco asserts that over the past three years, stranded transportation demand fees have resulted in $4.2 million in stranded costs, and that Texaco experienced an estimated $34 million (inclusive of stranded demand costs) needed to replace gas that did not flow under the firm transportation agreement with Texaco.

ONEOK

The affidavit submitted on behalf of ONEOK states that scheduling cuts for seven contracts of ONEOK for the period March 2001 through June 2001 were as follows: for Contract No. 9DQH, 5% in March, 13% in April, 11% in May and 21% in June; for Contract No. 9KQX, 8% in March and April, 15% in May and 3% in June; for Contract No. 9M8X, 22% in April, 20% in May and 49% in June; for Contract No. 9M88, 23% in April, 10% in May and 2% in June; for Contract No. 9M89, 19% in April, 18% in May and 2% in June; for Contract No. 9MG6, 9% in April, 11% in May and 2% in June; for Contract No. 9M84, 10% in April, 9% in May and 35% in June.

Coral and Aera

Similarly, the affidavit submitted at the public conference on behalf of Coral and Aera states that Cycle 4 cuts for this period where Coral or Aera was the shipper were 6,013,222 Dt, and the total stranded demand charges were $659,992. Lost revenues associated with having to find alternative markets were $797,204.95, and lost revenues associated with having to find alternate suppliers were $2,966,463. The affidavit also states that there were additional costs associated with manpower.

OEMI

The affidavit submitted on behalf of OEMI states that for the period of January 1, 1999 through December 31, 2001, OEMI experienced total volume cuts of 1,212,394 MMBtu and total stranded demand charges of $432,590. Lost revenues associated with having to find alternative markets were $1,079,338. The affidavit further states that OEMI incurred additional manpower costs.

SoCalGas

In its May 15, 2002 data response, SoCalGas provided calculations supporting its claim of stranded demand charges. SoCalGas calculates that total stranded demand charges resulting from Cycle 4 cuts (taking the difference between what was nominated in Cycle 1 and what was scheduled in Cycle 4) were $27.8 million for the years 1999 through 2001. SoCalGas estimates its replacement costs of gas to be $164 million for those years.

Indicated Shippers

In its May 15, 2002 data response, Indicated Shippers filed additional data in the form of invoices and further explanation to substantiate the earlier affidavits filed by BP Energy, OEMI, and Texaco. BP Energy points out that one of its transportation contracts (97JB) has the San Juan Basin as its only primary receipt point yet it consistently receives monthly curtailments. Texaco elaborates that it was damaged in 32 out of 36 months and stranded almost 12 Bcf of gas transportation.

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EXHIBIT JAC-3

PHOENIX ADM. OFFICE

BEFORE THE ARIZONA CORPORATION COMMISSION

RENZ D. JENNINGS
CHAIRMAN
MARCIA WEEKS
COMMISSIONER
CARL J. KUNASEK
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF CITIZENS UTILITIES COMPANY, NORTHERN ARIZONA GAS DIVISION, FOR AN ORDER APPROVING THE PROPOSED TARIFF FOR THE NEGOTIATED SALES PROGRAM.	DOCKET NO. E-1032-94-425
IN THE MATTER OF THE APPLICATION OF CITIZENS UTILITY COMPANY, NORTHERN ARIZONA GAS DIVISION, FOR A DECREASE IN ITS PURCHASED GAS ADJUSTMENT RATE, FOR THE ESTABLISHMENT OF A TRUST FUND ACCOUNT, AND FOR THE RECOVERY OF CERTAIN CAPACITY COSTS.	DOCKET NO. E-1032-95-079 DECISION NO. 59399 **OPINION AND ORDER**

Arizona Corporation Commission
DOCKETED
NOV 28 1995
DOCKETED BY SS

DATE OF HEARING: August 2, 1995

PLACE OF HEARING: Phoenix, Arizona

PRESIDING OFFICER: Lyn Farmer

IN ATTENDANCE: Marcia Weeks, Commissioner

APPEARANCES: Beth Ann Burns, Associate General Counsel, on behalf of Citizens Utilities Company;

Elaine Williams, Chief Counsel, on behalf of the Residential Utility Consumers Office; and

Janet Wagner, Staff Attorney, Legal Division, on behalf of the Arizona Corporation Commission.

BY THE COMMISSION:

On December 12, 1994, Citizens Utilities Company ("Citizens" or "Company") Northern Arizona Gas Division ("NAGD") filed an application with the Arizona Corporation Commission ("Commission") for approval of the proposed tariff for the Negotiated Sales Program ("NSP").

On February 21, 1995, Citizens NAGD filed an application with the Commission to approve a decrease in the Purchased Gas Adjustment ("PGA") rate to a negative \$0.01 per therm, establish a trust fund account for the over-recovered bank balance, and permit cost recovery of 1,600 dekatherms ("Dth") of capacity for the Flagstaff, Arizona service area. By Procedural Order dated April 18, 1995, the above-captioned matters were consolidated. By Procedural Order dated June 7, 1995, a hearing in this matter was set for August 1, 1995. Upon Staff's Motion to Continue, the hearing was rescheduled to commence on August 2, 1995.

In Decision No. 59120 (June 8, 1995) the Commission ordered that the Company's PGA rate decrease from a positive $0.027 per therm to a negative $0.04 per therm until a final decision is reached in this proceeding, in order to slow the growth of the over-collected bank balance. The Commission also ordered a one-time refund of $5,000,000 of the over-collected bank balance.

On August 2, 1995, a hearing was held before a duly authorized Hearing Officer of the Commission in Phoenix, Arizona. At the conclusion of the hearing, the Hearing Officer took the matter under advisement pending submission of a Recommended Opinion and Order to the Commission. The parties filed their post-hearing briefs on September 14, 1995.

DISCUSSION

TRANSWESTERN CAPACITY CHARGES

In July 1990, the predecessor owner of the NAGD, Southern Union Gas ("SUG"), entered into a contract for firm capacity with the Transwestern Pipeline Company ("Transwestern"). The contract provided, in part, for a maximum daily quantity of 25,000 Dth of capacity: 10,000 Dth for delivery to the Kingman service area and 15,000 Dth for the Flagstaff service area. At the time of contracting with Transwestern, SUG had a full requirements contract with another pipeline, El Paso Natural Gas ("El Paso"). In 1991, Citizens acquired the NAGD and assumed the contractual relationships of SUG pertaining to the El Paso and Transwestern pipelines. Decision No. 57647 (December 2, 1991) approved Citizens and SUG's joint application for transfer of assets and Certificates of Convenience and Necessity, and also subjected Citizens to those terms and conditions previously imposed upon SUG by the Commission concerning its PGA mechanism.

At issue in Citizens' rate case filed May 3, 1993, was the propriety of passing pipeline charges from Transwestern through the PGA mechanism to ratepayers. The Commission determined in Decision No. 58664 (June 16, 1994) that "SUG's decision to contract with Transwestern for a second source of supply was prudent, but that full recovery of the Transwestern reservation charges is precluded since a portion of the contract quantity of 25,000 Dth represents unreasonable excess capacity." The Commission ordered that the Company exclude from its PGA as fixed reservation costs all Transwestern reservation costs charged for daily capacity in excess of 8,400 Dth for service to Kingman. The Commission also disallowed recovery in the PGA the daily capacity in excess of 1,460 Dth for service to Flagstaff "continuing until Citizens has installed distribution facilities to permit full access to the 15,000 Dth of Transwestern capacity at Flagstaff."

Subsequent to the issuance of Decision No. 58664, in November and December of 1994, the Company placed in service expanded distribution facilities which allow the Company to fully access the Transwestern capacity reserved for service to Flagstaff. Also subsequent to the issuance of Decision No. 58664, the Company entered into an agreement with Transwestern to amend its transportation contract to provide for maximum daily deliveries to Flagstaff of 16,600 Dth, an increase which represents the reassignment of 1,600 Dth of capacity previously assigned to Kingman. As a result of the amendment, the total contract quantity remains 25,000 Dth, with 8,400 Dth assigned to Kingman and 16,600 Dth assigned to Flagstaff.

On June 30, 1995, El Paso filed an application for a rate increase with the Federal Energy Regulatory Commission ("FERC") to recover deficiencies resulting in part from the step down of 300,000 Dth per day of Southern California Gas Company capacity. As a result of using the Transwestern capacity, Citizens has reduced its dependency on El Paso as reflected in its El Paso billing determinants being lowered by 22 percent, from 54,905 Dth to 42,599 Dth.[1] The Company projects that the El Paso reservation rate will increase by seventy percent, from $5.5260 to $9.4098. It is expected that the rates will go into effect, subject to refund, on January 1, 1996.

The Company believes that Decision No. 58664 authorized it to begin recovering the Flagstaff capacity costs in the PGA once it had installed the facilities allowing access to that capacity. In December 1994, the Company began including in the PGA bank balance all of the Transwestern capacity charges associated with Flagstaff, which has had the effect of offsetting (reducing) the Company's over-collected bank balance. As of May 1995, the Company had included $688,359.54 of these costs in the

[1] Although the billing determinants have been lowered, Citizens must still pay El Paso for the higher amount until the billing determinants are adjusted in El Paso's pending rate application.

PGA, and by year-end 1995, will have included approximately $1.5 million.

With this application, the Company requests full recovery of the Transwestern charges because it believes that the capacity is fully utilized to serve current customers, provides long-term economic benefit to current and future customers, and through diversification of supplies, has substantially improved the reliability of service and reduced dependency on El Paso.

Staff believes that even though Citizens now has access to all the Transwestern capacity, a portion of the total pipeline capacity currently under contract is not used and useful.[2] According to Staff, although the Transwestern contract has allowed Citizens to displace El Paso capacity, the cost of capacity purchased from El Paso has not and will not be reduced until the El Paso billing determinants are adjusted in the pending El Paso rate case at the FERC, and until such time, the capacity charges paid to El Paso and Transwestern are duplicative. Staff recommends that the current capacity surplus should be priced at El Paso capacity charges, and the cost of excess capacity should be shared equally between the Company and its ratepayers. According to Staff, this would result in a disallowance of approximately $50,000 per month. Staff and Citizens believe that once the El Paso billing demand is adjusted downward, then the "excess capacity" issue and disallowance should no longer exist. Staff recommends that this disallowance begin with December 16, 1994, the date that Citizens informed the Commission that the necessary Flagstaff distribution facilities were in place, and continue until such time as the El Paso billing demand decreases to approximately 42,599 Dth, which is anticipated to occur on January 1, 1996.

RUCO disagrees with the Company that Decision No. 58664 authorized the Company to begin including in the PGA all disallowed costs associated with the Transwestern pipeline capacity in the Flagstaff area upon completion of facilities necessary to provide access. RUCO concludes that the Commission has not authorized the Company to recover any of the disallowed Transwestern capacity costs, and, accordingly, the ratepayers are entitled to a refund of the full amount that has been recorded in the PGA. Furthermore, RUCO also argues that a decision to change the PGA rate to allow recovery of Flagstaff capacity in this proceeding would violate sound regulatory principles that preclude

[2] Staff calculates the excess capacity to be 18,110 Dth.

retroactive adjustments to established rates and would conflict with rulings in Scates v. Ariz. Corp. Comm'n, 118 Ariz. 531, 578 P.2d 612 (Ariz. App. 1978) and with Arizona's constitutional provisions regarding ratemaking.

We find that Decision No. 58664 did not automatically authorize Citizens to collect the Transwestern capacity costs in the PGA once it had established full access to the Flagstaff Transwestern capacity. Finding of Fact No. 23 found that because a portion of the contract quantity of 25,000 Dth represented unreasonable excess capacity, full recovery of the Transwestern reservation charges was precluded. Finding of Fact No. 28 agreed with Staff's recommendation to disallow 90.27 percent of the contracted capacity for Flagstaff. This 90.27 percent disallowance was to continue until the distribution facilities were installed. Once the facilities were in place, then the question of the amount of "excess capacity" needed to be addressed. This is the issue that must be decided in this proceeding.[3] We do not believe that a change in the amount of the disallowance would violate ratemaking principles or the Constitution because, as a practical matter, although Decision No. 58664 postponed the determination of the disallowance until the facilities were in place, it put everyone on notice that such a determination would be made and was considered during the setting of rates in that proceeding.

The real issue that needs to be decided is who should bear the cost of this additional capacity. The additional capacity has resulted in an increase in the total amount Citizens pays for capacity, but it has also resulted in reducing Citizens' dependence on El Paso by lowering the billing demand on the El Paso pipeline and thereby ameliorating expected El Paso rate increases; it has improved reliability of service and placed pressure on El Paso to improve service quality; and has provided the opportunity for obtaining lower cost gas supplies.

RUCO's recommendation to totally disallow the cost of the Transwestern capacity fails to recognize the benefits associated with having a second pipeline supplier. Given these benefits, it is not appropriate to disallow all the Transwestern capacity charges. After weighing these costs and benefits, we believe that the Staff recommendation to share the costs of the excess capacity between ratepayers and shareholders recognizes these benefits and represents a fair way to apportion these additional capacity

[3] The term "excess capacity" is a misnomer in the sense that as long as Citizens has a full requirements contract with El Paso, any additional capacity from other sources is excess.

costs. We find that the appropriate costs to be shared are the capacity charges for the 15,140 Dth[4] priced at El Paso capacity charges from December 1994 forward until the billing demand is lowered as discussed above.[5] The PGA bank balance to be refunded should be adjusted to reflect the accumulated capacity disallowance from Decemer 16, 1994 through December 31, 1995. If the billing demand is lowered on January 1, 1996, then no further "per therm" disallowance is necessary. If however, the billing demand does not decrease to 42,599 Dth or less on January 1, 1996, a per therm disallowance of negative $.0064 should be added to the transportation and variable demand cost component of the PGA. Any variance from the anticipated billing demand amount and/or effective date will require the Commission to re-evaluate at a later proceeding whether or not the entire 15,140 Dth should be disallowed from January 1, 1996 forward. We find that this is a reasonable and appropriate method to apportion the costs and accordingly, we will deny Citizens' request to allow it to offset the disallowances against any savings which may be realized in the future under the Transwestern contract.

PGA REVISION

Citizens has experienced several sizable fluctuations in its bank balance in the last few years that have resulted in both under-collections and over-collections. According to the Company, these swings in gas cost recovery cause rate instability for customers, earnings volatility for the Company, and result in rates that do not track the cost of service and do not send the appropriate price signals to customers. In order to make the PGA operate more effectively, both Staff and Citizens proposed revising the PGA. The proposed revisions will establish four PGA components: the commodity costs; the commodity cost bank balance; the transportation variable and demand costs; and the transportation variable and demand costs bank balance. The following proposed revisions were not opposed by any party:

. . .

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[4] This is the current capacity disallowance established in Decision No. 58664. Although there was some testimony concerning the appropriate service reliability standard, we do not believe that the evidence on the record is sufficient to make such a determination at this time, nor is such a determination necessary in this proceeding. However, Citizens should be aware of this potential issue in future proceedings and should note the discussion in Staff's Brief concerning this issue.

[5] All parties agreed that the capacity should be priced at El Paso rates. This results in a disallowance of approximately $45,000 per month.

Commodity Costs

The PGA rate would include a commodity cost component that would change monthly, based upon the rolling twelve month average of actual purchased gas costs.[6] The monthly report filed by the Company will include the cost and quantity of gas purchased during the most recent twelve months and the commodity component of the PGA rate will be adjusted after Staff completes its review and approval of this data. A triggering mechanism would precipitate Commission review if the monthly commodity rate varies from the base commodity rate by more than $0.03 per therm. A cost change that triggers this mechanism will become effective up to plus or minus $0.03 per therm and inclusion of the remaining portion of the change (i.e., the amount in excess of the trigger) will be deferred pending the outcome of the Commission's review.

Commodity Cost Bank Balance

The Company proposes to create a bank balance that would monitor the differences between the commodity costs included in the PGA rate and the actual commodity costs incurred. The commodity cost component of the PGA rate would be adjusted each month to reconcile that bank balance. There would be a two month lag in the reconciliation due to allowance for receipt, review, and recording of supplier invoices.[7]

Transportation Variable and Demand Cost

The treatment of transportation and demand costs would not change. These costs would continue to be included in the base cost of gas at the rate established by the Commission. As is currently the case, the Company will file a PGA case immediately following any known and measurable change in transportation costs that represent a 7.5 percent increase or decrease from the authorized transportation demand rate.

Transportation Variable and Demand Cost Bank Balance

The reconciliation of transportation demand costs will remain the same as under the current clause. The difference between the transportation demand costs included in the PGA and the actual

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[6] This rolling average would replace the current requirement of forecasting future gas prices.

[7] For example, the commodity cost bank balance for January would be reconciled in the March commodity cost component of the PGA rate.

transportation costs incurred by the Company will be maintained in a separate, transportation variable and demand cost, bank balance. The bank balance will accrue until the trigger point is reached, at which time the Commission will review and reconcile the accrued balance.

Although RUCO did not oppose the changes to the PGA, its witness did express reservations about customer understanding and response to the monthly change in the PGA rate. The Company indicated that it will undertake notification by bill insert and continue to inform and educate customers about the revised PGA mechanism. The revisions will require Staff to closely monitor the Company's monthly reports and verify the bank balance reconciliations. The revisions do not in any way modify or impede the Commission's ability to review these costs and bank balances during a PGA review or rate proceeding. The Company stated that should a PGA case or rate proceeding not otherwise occasion a review, it would not object to a requirement for an annual PGA review and hearing.

We agree with Staff and the Company that the proposed revisions to the PGA (including the monthly commodity rate and the commodity cost bank balance reconciliation) will allow customers to make more informed usage choices than with the current PGA mechanism's reliance on refunds and adjustments that do not correspond as closely in time to prevailing market conditions. Accordingly, we will approve these unopposed PGA revisions.

<u>TREATMENT OF THE CURRENT BANK BALANCE</u>

In its PGA application, Citizens requested that the Commission approve the establishment of an interest bearing trust fund account for the over-collected bank balance and that it be used to offset the effect of new rates expected to result from Citizens' now pending application for a rate increase. Citizens withdrew the proposal after the Commission issued Decision No. 59120 which ordered a five million dollar refund of the then over-collected bank balance.

The Company now recommends that if the Commission adopts the proposed PGA revisions, then, as of the date the new mechanism becomes effective, the existing balance be frozen and "zeroed out" by bill credit or refund to customers. The Company believes that this would help in the transition from an accrual account to the establishment and maintenance of separate bank balances for the commodity cost component and the transportation variable and demand cost component of the PGA.

We agree with the Company. As of January 1, 1996, the Company should establish the new separate bank balances, each with a balance of zero. The existing over-collected PGA bank balance, as adjusted for the Transwestern capacity disallowance, shall be refunded to customers through one-time checks to be issued no later than March 18, 1996, and should be prorated to customers based on usage for the twelve month period beginning January 1, 1995 through December 31, 1995. Citizens shall apply the amount of any refund owed as a bill credit for those accounts that became delinquent and were disconnected during the 12-month period; not issue a check for a refund less than $1.00; and withhold the estimated administrative costs of the refund, including the cost of the checks, processing costs, and mailing and postage expenses pending final recommendation and audit by Commission Staff.

NEGOTIATED SALES PROGRAM TARIFF

In its application in Docket No. E-1032-94-425, Citizens requests approval of a tariff to provide a new type of service, the Negotiated Sales Program ("NSP"). Through the NSP, Citizens would offer to obtain the gas supply requirements for its transportation customers. The application identified three primary purposes of the NSP, including: to provide a competitive alternative to current and future transportation customers in procuring gas supplies to meet their needs; to provide for lowering gas costs to firm sales customers through a sharing of the margins realized from NSP sales; and to provide the Company an opportunity to improve its earnings.

According to the Company, it will request each transportation customer to allow it to submit a bid to supply gas supply needs at the end of the term of its existing contracts. The Company will use its upstream pipeline capacity to transport NSP volumes, except during periods when capacity is needed to serve firm sales customers (the heating season from November through March). The Company will direct charge the NSP gas cost account for all variable costs billed by upstream pipelines and credit the gas bank account for fifty percent of the sales margin. The Company will maintain separate accounts for the NSP to record revenues, gas costs, and transportation expense.

Both RUCO and Staff supported the NSP tariff, with the imposition of several additional terms and requirements. Staff recommended that the minimum term of NSP contracts should be set at twelve months and the contracts should specify and document any alternative supply arrangements for gas deliveries between November 15 and March 15. Staff also recommended that in order to avoid a situation in which Citizens has an incentive to encourage customers to migrate from ordinary bundled service to NSP service, the Company should not be permitted to keep any portion of the margin on NSP sales that are made to a customer that has taken bundled service at any time during the last three years. Staff further recommended that the appropriate sharing of NSP margins should be reviewed in future base rate and PGA cases, and that the future disposition of NSP margins should be based on an assessment of the magnitude of NSP costs and benefits, and the extent to which the Company actually experiences exposure to a risk of loss.

Citizens did oppose Staff's recommendation to require minimum twelve month NSP contracts which specify and document alternative supply arrangements for gas deliveries during the heating season. The Company opposed Staff's recommendation that the Company should not be permitted to keep any portion of the margin on NSP sales made to customers that have taken bundled service during the last three years. According to the Company, it does not intend to encourage a sales customer to migrate to transportation service in hope of being selected as the gas supplier for the customer under the NSP tariff, as the Company states that it and its customers are better off if the customer retains sales service rather than NSP service. It is clear that both the Company and its customers do benefit if existing transportation customers become NSP customers, but it is not clear whether there would be an incentive for Citizens to encourage sales service customers to become NSP customers or whether such a move would benefit the Company and/or the non-NSP customers. Accordingly, we agree with Staff that at least initially, the Company should not be permitted to keep any portion of the margin on NSP sales made to customers who have taken bundled service at any time during the last three years. We also agree with Staff that the appropriate amount of "margin sharing" should be evaluated in future rate and PGA proceedings. The NSP sales margins, as discussed herein, should be credited to the transportation variable and demand cost bank balance.

RUCO recommended that for every sale of gas to an NSP customer under the tariff, Citizens should be required to assign an equivalent volume of gas to PGA customers at the same or lower price. RUCO also recommended that Citizens should provide assurance to the Commission that no cross-subsidization results from implementation of the tariff, and that the tariff should be implemented on a trial basis, for an initial two-year period.

The Company had no objection to RUCO's recommendation that it should submit a monitoring plan to Staff to ensure that no cross-subsidy occurs from sales schedule customers to NSP customers. The Company objected to RUCO's recommendation to " price match" volumes of NSP and PGA gas. According to the Company, it will not obtain an overall gas supply and then allocate a portion of those volumes to NSP sales, but will obtain contracts for separate and distinct gas supplies for each transportation customer. Since there will be no commingling of jurisdictional gas supplies with NSP gas supplies, the Company believes that no assignment or allocation of volumes is possible.

RUCO's recommendation has merit in that there is a direct incentive for the Company to find and procure the lowest price gas supply for NSP customers, while there is no corresponding direct incentive for the Company to find and procure the lowest price gas supply for PGA customers. However, given the Company's explanation of its procurement procedures, we agree with the Company that assignment or allocation of volumes is not possible. We believe that RUCO's concerns can be addressed through review and close monitoring of the Company's procurement practices. To that end, instead of implementing the tariff on a two year trial basis as recommended by RUCO, we believe that the NSP tariff, and Citizens' procurement practices should be reviewed two years from the date of this Decision.

In its NSP application, Citizens requested that the Commission exempt sales under the NSP from the regulatory assessment in order to place Citizens on a more equal basis with its competitors, who are non-regulated brokering firms. Staff recommended that the request be denied because Staff believes that the stature regulating assessments requires application to all jurisdictional revenues, which would include NSP sales. The Company did not pursue the request, and accordingly, we will not grant such an exemption.

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. Citizens is a Delaware corporation providing natural gas utility service to the public through the NAGD, in portions of Apache, Coconino, Mohave, Navajo, and Yavapai Counties, Arizona, pursuant to authority granted by the Commission.

2. On December 12, 1994, Citizens filed an application with the Commission for approval

of the proposed tariff for the Negotiated Sales Program.

3. On February 21, 1995, Citizens NAGD filed an application with the Commission to approve a decrease in the PGA rate, establish a trust fund account for the over-recovered bank balance, and permit cost recovery of 1,600 Dth of capacity for the Flagstaff, Arizona service area.

4. By Procedural Order dated April 18, 1995, the above-captioned matters were consolidated.

5. By Procedural Order dated June 7, 1995, a hearing in this matter was set for August 1, in Phoenix, Arizona and was subsequently rescheduled for August 2, 1995.

6. Notice of the hearing was published in a newspaper of general circulation in each county of the Company's service area.

7. The hearing was held as scheduled and no members of the public were present to make public comment.

8. SUG had a full requirements transportation contract with El Paso, and in July 1990, SUG entered into a contract for 25,000 Dth of firm capacity with Transwestern.

9. In 1991, Citizens acquired the NAGD and assumed the contractual relationships with El Paso and Transwestern.

10. Decision No. 58664 found that "SUG's decision to contract with Transwestern for a second source of supply was prudent, but that full recovery of the Transwestern reservation charges is precluded since a portion of the contract quantity of 25,000 Dth represents unreasonable excess capacity."

11. The Commission ordered that the Company exclude from its PGA as fixed reservation costs all Transwestern reservation costs charged for daily capacity in excess of 8,400 Dth for service to Kingman and also that capacity in excess of 1,460 Dth for service to Flagstaff "continuing until Citizens has installed distribution facilities to permit full access to the 15,000 Dth of Transwestern capacity at Flagstaff."

12. Subsequent to the issuance of Decision No. 58664, in November and December of 1994, the Company placed in service expanded distribution facilities which allow the Company to fully access the Transwestern capacity reserved for service to Flagstaff.

13. In December 1994, the Company began including in the PGA all of the Transwestern capacity charges associated with Flagstaff, which has had the effect of offsetting (reducing) the

Company's over-collected bank balance, and as of May 1995, the Company had included $688,359.54 of these costs in the PGA, and by year-end 1995, will have included approximately $1.5 million.

14. Decision No. 58664 did not authorize Citizens to recover the previously disallowed costs upon completion of the facilities prior to our determination of the amount of "excess capacity."

15. On June 30, 1995, El Paso filed a rate application with FERC and new rates are expected to go into effect January 1, 1996, subject to refund.

16. The issue of "excess capacity" will no longer exist if the billing determinants decrease to approximately 42,599 Dth as of January 1, 1996.

17. The Transwestern capacity has resulted in an increase in the total amount Citizens pays for capacity.

18. The Transwestern capacity has provided potential benefits to customers, including reducing Citizens' dependence on El Paso by lowering the billing demand on the El Paso pipeline and thereby ameliorating expected El Paso rate increases; improving reliability of service and placing pressure on El Paso to improve service quality; and by providing the opportunity for obtaining lower cost gas supplies.

19. Based on the circumstances presented herein, the Staff recommendation to share the costs of the duplicative capacity equally between the Company and the ratepayers is reasonable and appropriate.

20. The PGA bank balance should be adjusted to reflect the disallowance of fifty percent of the 15,140 Dth, priced at El Paso capacity charges, from December 16, 1994 to December 31, 1995.

21. The existing over-collected PGA bank balance as of January 1, 1996, as adjusted for the Transwestern capacity disallowance, should be refunded to customers through one-time checks to be issued no later than March 18, 1996, and should be prorated to customers based on usage for the twelve month period beginning January 1, 1995 through December 31, 1995.

22. The currently effective composite PGA recovery rate is $0.2600 per therm, which is comprised of the $0.3000 per therm base rate established in Decision No. 58664, and the PGA adjustment rate of negative $0.04 per therm established in Decision No. 59120.

23. The current PGA rate of negative $0.04 per therm should remain in effect, with the

transportation and variable demand cost component set at $0.084 per therm, and the gas commodity cost component set at $0.176 per therm, as adjusted for the twelve month rolling average commodity cost per therm sold.

24. If the El Paso billing determinants do not decrease as projected by Citizens on January 1, 1996, then an additional negative transportation and variable demand cost PGA factor of $0.0064 should be implemented.

25. The proposed revisions to the PGA are designed to allow customers to make more informed usage choices than are possible with the current PGA mechanism.

26. The proposed revisions to the PGA as contained in the Discussion herein, including the creation of two separate cost components to the PGA rate and two separate bank balances, should be adopted.

27. Citizens shall notify its customers by bill insert of the revisions to the PGA mechanism and shall inform and educate the customers about the effects of such a revision on a continuing basis.

28. As of January 1, 1996, the Company shall establish the new separate bank balances, each with a balance of zero, and shall include in its monthly PGA reports all activity affecting the bank balances.

29. Citizens shall file monthly PGA reports that include the cost and quantity of gas purchased during the most recent twelve months and should adjust the commodity component of the PGA rate only after Staff completes its review and approval of the data.

30. The PGA revisions adopted herein do not modify or impede the Commission's ability to review costs and bank balances during a PGA case or rate proceeding.

31. After the revised PGA mechanism has been in effect for one year, Citizens shall apply for a PGA review proceeding to be conducted and annually thereafter, unless such a review is conducted in conjunction with a rate proceeding or other PGA proceeding.

32. Citizens has proposed an NSP tariff whereby it would offer to obtain the gas supply requirements for its transportation customers.

33. Both Staff and RUCO generally supported the NSP tariff, with the imposition of several additional terms and requirements.

34. Staff's recommendation to require a minimum NSP contract term of twelve months, with the contract specifying and documenting any alternative supply arrangements for gas deliveries during the heating season, is reasonable and should be adopted.

35. Staff's recommendation that the Company should not be permitted to keep any portion of the margin on NSP sales that are made to a customer that has taken bundled service at any time during the last three years is appropriate at this time given the lack of evidence on the effect the migration from sales to NSP customers would have on the Company and its customers.

36. Staff's recommendation that the appropriate sharing of NSP margins should be reviewed in future base rate and PGA cases, and that the future disposition of NSP margins should be based on an assessment of the magnitude of NSP costs and benefits, and the extent to which the Company actually experiences exposure to a risk of loss, is reasonable and should be adopted.

37. RUCO recommended that for every sale of gas to an NSP customer under the tariff, Citizens should be required to assign an equivalent volume of gas to PGA customers at the same or lower price.

38. As explained by the Company, its procurement practices do not allow the assignment of equivalent volumes of gas to NSP and PGA customers.

39. RUCO recommended that Citizens should provide assurance to the Commission that no cross-subsidization results from implementation of the tariff, and that the tariff should be implemented on a trial basis, for an initial two-year period.

40. Citizens should submit a monitoring plan to Staff to ensure that no cross-subsidy occurs from sales schedule customers to NSP customers.

41. The Company's procurement practices should be closely monitored by Staff and Citizens should apply for a formal NSP review to be conducted no later than two years from the date of this Decision to ensure that the Company's procurement practices are reasonable and that the NSP program is appropriate and does not result in cross-subsidization.

CONCLUSIONS OF LAW

1. Citizens is a public service corporation within the meaning of Article XV, Section 2, of the Arizona Constitution.

2. The Commission has jurisdiction over Citizens and the subject matter of these applications.

3. Notice was provided in accordance with the law.

4. The Transwestern capacity disallowance as discussed herein is reasonable and appropriate.

5. The PGA revisions, as discussed herein, are reasonable and should be adopted.

6. The Company's proposed NSP tariff should be approved with the modifications and conditions contained herein.

7. The currently effective composite PGA recovery rate of $0.2600 per therm should remain in effect, with the transportation variable and demand cost component set at $0.084 per therm, and the gas commodity cost component at $0.176 per therm, as adjusted for the twelve month rolling average commodity cost per therm sold.

8. The existing over-collected PGA bank balance as of January 1, 1996, as adjusted for the Transwestern capacity disallowance through December 31, 1995, should be refunded to customers through one-time checks to be issued no later than March 18, 1996, and should be prorated to customers based on usage for the twelve month period beginning January 1, 1995 through December 31, 1995.

9. If the El Paso billing determinants do not decrease on January 1, 1996, then an additional negative transportation and variable demand cost PGA factor of $0.0064 should be implemented.

ORDER

IT IS THEREFORE ORDERED that Citizens Utilities Company, Northern Arizona Gas Division, shall adjust the Purchased Gas Adjustment bank balance to reflect the disallowance adopted herein for the Transwestern Pipeline Company capacity.

IT IS FURTHER ORDERED that the disallowance of Transwestern capacity adopted herein terminate on December 31, 1995, provided that Citizens Utilities Company, Northern Arizona Gas Division's billing demand on the El Paso system decreases to 42,599 Dth or less as of January 1, 1996.

IT IS FURTHER ORDERED that if the El Paso billing determinants do not decrease as contemplated herein, Citizens Utilities Company Northern Arizona Gas Division shall adjust the transportation variable and demand commodity cost component to reflect the continuing disallowance adopted herein for the Transwestern Pipeline Company capacity.

IT IS FURTHER ORDERED that the Purchased Gas Adjustment mechanism is revised effective January 1, 1996, consistent with the Discussion, Findings, and Conclusions contained herein.

IT IS FURTHER ORDERED that Citizens Utilities Company Northern Arizona Gas Division shall refund the amount of the over-collected PGA bank balance, as adjusted for the capacity disallowance adopted herein, as of January 1, 1996, in accordance with the Discussion, Findings, and Conclusions contained herein.

IT IS FURTHER ORDERED that the current PGA rate of negative $0.04 per therm shall remain in effect, with the transportation and variable demand cost component set at $0.084 per therm, and the gas commodity cost component set at $0.176 per therm, as adjusted for the twelve month rolling average commodity cost per therm sold.

IT IS FURTHER ORDERED that the Negotiated Sales Program tariff, with the modifications and conditions adopted in the Discussion, Findings, and Conclusions contained herein, is hereby approved.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN | COMMISSIONER | COMMISSIONER

IN WITNESS WHEREOF, I, JAMES MATTHEWS, Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 28 day of November, 1995.

James Matthews

JAMES MATTHEWS
EXECUTIVE SECRETARY

DISSENT

LAF/kjh

DECISION NO. 59399

SERVICE LIST FOR: CITIZENS UTILITIES COMPANY, NORTHERN ARIZONA GAS DIVISION

DOCKET NOS.: E-1032-94-425 AND E-1032-95-079

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EXHIBIT JAC-4

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NEW APPLICATION

00000-00001-0464

July 1, 1997

DOCKET NO. U-1032-97-345

Arizona Corporation Commission
DOCKETED

JUL 03 1997

DOCKETED BY

Docketing Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Dear Sirs:

Pursuant to Decision No. 59399 (November 28, 1995), Citizens Utilities Company ("Citizens" or "Company"), Northern Arizona Gas Division ("NAGD") hereby submits to the Arizona Corporation Commission ("Commission") this Application to request review of its Negotiated Sales Program ("NSP" or "Program") tariff. Citizens additionally requests approval of a modification to the NSP tariff to eliminate an unnecessary seasonal restriction on the use of the Company's upstream pipeline capacity to transport NSP volumes. The reasons for these requests are explained below:

REVIEW OF THE NSP

In Decision No. 59399, the Commission approved a tariff that authorized Citizens to offer the NSP as a new type of service. Under the NSP tariff, the Company competes in the highly competitive market for the provision of gas supplies to transportation customers. Citizens requests each transportation customer to allow the Company to participate in the bidding process the customer conducts to obtain its gas supply requirements. Citizens submits a bid, or sales price, to the transportation customer that is predicated on the cost of a specific gas supply that the Company can obtain to serve that customer's demands, based upon prevailing market conditions and the specific demand and usage requirements of the customer. When bids are successful, the Company utilizes its upstream capacity to transport the NSP volumes to the customer, except during periods when that capacity is needed to serve the NAGD's firm sales customers. Additionally, Decision No. 59399 prohibits the Company from utilizing its upstream pipeline capacity to transport NSP volumes during the heating season months of November through March.

The profit, or margin, earned on NSP sales is shared with Citizens' firm sales customers. The firm sales customers receive 100 percent of the margin on NSP sales to transportation customers who have taken bundled service from the NAGD at any time during the last three years, as an immediate credit to the Purchased Gas Adjustment ("PGA") clause bank balance. The margin on sales to transportation customers that have not taken bundled service from the NAGD within the last three years is shared 50/50 between the Company and the ratepayers.

In Decision No. 59399, the Commission approved the NSP tariff on a permanent basis, but directed that the tariff and the Company's procurement practices be reviewed two years from the effective date of the Decision. By this Application, Citizens requests that the required review be undertaken.

Citizens submits that, as a result of the review, the Commission should find the NSP to be a successful and highly beneficial service. In the application to implement the NSP, Citizens identified three benefits that would obtain from the Program and create a win-win situation for NAGD customers and the Company. Each of those benefits is being realized.

The first benefit is that the NSP provides transportation customers a competitive alternative for purchasing their gas requirements in the open market. The Company has been invited to submit competitive bids to the majority of its transportation customers. Currently, the Company is providing NSP sales service to five of its 16 transportation customers.

A second benefit is that the Program lowers the cost of gas to NAGD's firm sales customers. During this initial reporting period ending April 30, 1997, total margins realized from sales under the NSP were $203,949. The allocation of 50% of NSP margins from sales to transportation customers who had not taken bundled services within the last three years plus 100% of NSP margins from sales to transportation customers who had taken bundled service during the last three years was $111,234. This shared NSP margin has been credited to the PGA bank balance and resulted in a reduction in overall gas cost for the NAGD's firm sales customers.

As the third benefit, the NSP allows the Company an opportunity to increase its earnings by sharing in the margins realized from sales under the NSP. The Company's share of the margin realized from NSP sales to transportation customers who had not taken bundled service during the last three years was $92,714 during the initial reporting period.

In addition to these benefits contemplated in Citizens' application for approval of the NSP tariff, the Program has produced a fourth benefit. The NSP has enabled the Company to increase its transportation throughput and, thereby, increase revenues to the benefit of the Company and firm sales customers by providing a competitive alternative to a transportation customer, Ralston Purina, who was using a fuel other than natural gas in its operations. For example, prior to May, 1996, Ralston Purina was a minimal system sales customer using 36,480 therms of natural gas per year, primarily for domestic space and water heating. Ralston Purina used fuel oil in its animal food processing operations. Through the NSP, the Company has been able to provide Ralston Purina with a competitive alternative in cleaner burning natural gas. This caused Ralston to switch from fuel oil to natural gas in its processing operations. Natural gas usage at Ralston Purina's plant increased to 1,594,170 therms for the 12-month period ending April 1997. This represents an increase of 1,557,690 therms over its historical usage. The increased transportation throughput has in turn increased revenues, which benefits the Company and customers. Further, firm sales customers have received 100% of the margin realized on these NSP sales.

As a result of its review, the Commission should further find that Citizens has properly accounted for the NSP sales and revenues on its books. Verification that the Company has maintained separate accounting of the sales and gas purchases for each NSP customer is contained in Exhibit-NSP-1 attached to this Application. This schedule summarizes each customer's monthly NSP activity. Additional customer-specific detail is confidential, proprietary, legally-protected, or competitively sensitive and will be provided upon request by the Commission's Staff and upon execution of a protective agreement. Exhibit-NSP-2 verifies that the NSP margins were properly credited to the NAGD's PGA bank balance. This exhibit reconciles the monthly NSP sales margins to the credits reflected in the PGA transportation variable and demand cost bank balance that appear on Exhibit 1-A, line 32, of the Monthly Gas Informational Filings that Citizens submits to the Commission each month.

REQUEST FOR MODIFICATION OF THE NSP

As mentioned above, Decision No. 59399 approved the NSP subject to the restriction that, from November through March, Citizens not use its upstream capacity to transport NSP volumes to transportation customers. The restriction was intended to provide assurance that the Company would not experience an increase in pipeline reservation fees from El Paso Natural Gas Company ("El Paso") in an El Paso rate case for delivery of NSP volumes on the peak day during the heating season. During the restricted use periods, the Company uses alternative delivery capacity provided in the NSP gas purchase agreements with its suppliers.

Citizens proposes to eliminate this restriction from the NSP tariff as being unnecessary. On July 1, 1997, El Paso will place into effect rates and services resulting from the implementation of the long-term settlement reached between El Paso and its customers and approved by the Federal Energy Regulatory Commission on April 16, 1997. This settlement is for a term of ten years beginning January 1, 1996, and terminating on January 1, 2006. For the term of this settlement, the Company's billing determinants will remain at the settlement quantities and the Company will continue to receive full requirement service to meet its growing system demand without increases in cost do to increases in billing determinants. Therefore, increased utilization of the El Paso contract will be realized during the term of the settlement as the Company expands service to customers in its service area where El Paso is the primary supplier.

To further increase the utilization of the El Paso contract and generate additional NSP margins to share with customers, Citizens requests that the Commission eliminate the heating season restriction on utilization of the El Paso contract for delivering NSP gas to transportation customers. Absent the restriction, the Company will continue to manage its utilization of the El Paso contract in delivering NSP gas to insure that new peak day use of the El Paso system does not reflect delivery to NSP customers. Delivery to NSP customers under peak day weather conditions will be made through alternative delivery capacity under NSP purchase agreements with suppliers.

CONCLUSION

For the foregoing reasons, Citizens requests that the Commission undertake the required review of the NSP and find that it is a highly successful and beneficial program, that the Company has properly accounted for the NSP sales and revenues, and that the Program should be continued. Citizens further requests that the Commission approve the Company's proposed modification to the NSP tariff to eliminate the unnecessary seasonal restriction on the use of the Company's upstream capacity to transport NSP volumes to transportation customers.

If you have any questions or require further information regarding this filing, please contact Mr. Jeffrey D. Richoux, Manager of Rates and Regulatory Affairs - Public Services Sector, at (504) 374-7449.

Very truly yours,

Beth Ann Burns

Beth Ann Burns
Associate General Counsel

cc: RUCO
attachments

CITIZENS UTILITIES CO.
ARIZONA GAS DIVISION
Transportation Imbalance &
NSP Margin Analysis Report

NSP TOTALS

	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1 Vol Sold to Customer	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2 Sales Price	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
3 Gross Sales Recognized (no ACA tax)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
4 ACA Tax	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
5 Sales Revenue Recognized	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
6 Gas Cost	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
7 City Gate Delivery	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
8 Gas Pipeline	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
9 [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
10 Commodity T-port	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
11 Total Gas Cost	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
12 Gas Cost Recognized	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
13 NSP Margin Recognized	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
14 Margin Shared CUC	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
15 Margin Shared Rate Payer	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
16 Deferred Gas Cost Balance	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
17 Commodity	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
18 Supply/Dem	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
19 Transport	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
20 Total	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
21 [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
22 [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
23 [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
24 [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

[illegible]

	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1 [illegible]	47,[illegible]	57,103.0	56,414.0	63,131.7	66,432.1	61,701.6	66,534.1	66,940.0	[illegible]	64,765.0	63,942.0
2 [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
3 [illegible]	84,817.29	[illegible]	109,328.13	[illegible]	[illegible]	110,130.[illegible]	113,543.[illegible]	109,[illegible]	[illegible]	[illegible]	110,701.18
4 [illegible]	[illegible]	[illegible]	186.85	202.02	229.97	192.11	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
5 [illegible]	84,[illegible]	[illegible]	109,143.56	[illegible]	120,740.02	[illegible]	113,350.02	110,313.[illegible]	[illegible]	[illegible]	[illegible]
6 [illegible]											
7 [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
8 [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
9 [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
10 [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
11 [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
12 [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
13 [illegible]	[illegible]	12,101.31	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
14 [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
15 [illegible]	[illegible]	[illegible]	[illegible]	1,772.28	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
16 [illegible]											
17 [illegible]	[illegible]	[illegible]	64,310.0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
18 [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
19 [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
20 [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
21 [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	(10,271.17)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
24 [illegible]	[illegible]	[illegible]	64,310.0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
25 [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
26 [illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

EXHIBIT NO.

G-WOO-HOC-[illegible]

CITIZENS UTILITIES CO.
ARIZONA GAS DIVISION
Transportation Imbalance &
NSP Margin Analysis Report

	NSP TOTALS	Aug-96	Sep-96	Oct-96	Nov-96	Dec-96	Jan-97	Feb-97	Mar-97	Apr-97	CUMULATIVE (TO DATE)
1	Vol Sold to Customer	65,795.6	85,175.4	100,874.5	96,789.9	91,291.0	104,274.7	94,614.3	92,190.3	80,714.6	1,698,879.3
2	Sales Price	1.2480	1.2111	1.6681	2.2020	2.2020	2.2020	2.2020	2.2020	1.7000	[illegible]
3	Gross Sales Recognized (inc ACA tax)	115,144.90	150,644.96	173,323.93	212,489.36	200,578.78	229,792.95	208,710.18	202,919.29	138,902.72	$3,379,999.00
4	ACA Tax	185.41	255.98	294.56	380.97	343.92	388.22	350.81	345.62	266.10	[illegible]
5	Sales Revenue Recognized	114,949.00	150,388.32	173,029.37	212,108.79	200,235.06	229,384.43	208,359.37	202,567.60	138,636.62	$3,374,870.00
6	Gas Cost										
7	City Gate Delivery	0.0000	0.0000	0.0000	2.1550	2.1550	2.1950	2.1550	2.1550	0.0000	
8	Intra Pipeline (1)	1.1440	1.4780	1.4690	0.0000	0.0000	0.0000	0.0000	0.0000	1.6400	
9	Fuel ...	0.0000	0.0347	0.0345	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
10	Commodity T-port	0.0315	0.0144	0.0143	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
11	Total P-line Del	1.1886	1.5251	1.5180	2.1550	2.1550	2.1950	2.1550	2.1550	1.6800	
12	Gas Cost Recognized	100,840.86	134,141.22	157,801.07	207,429.08	195,928.47	223,781.90	203,463.95	197,771.71	149,891.08	$3,078,424.75
13	NSP Margin Recognized	14,108.43	16,296.07	15,228.30	4,675.70	4,306.72	4,872.51	4,893.42	4,795.86	14,976.22	203,848.66
14	Margin Shared CUC	8,296.62	8,285.00	8,108.75	2,081.29	1,891.18	2,204.85	2,001.24	1,928.66	6,988.82	[illegible]
15	Margin Shared Rate Payer	2,811.84	8,011.07	6,498.54	2,594.41	2,414.41	2,767.66	2,892.08	2,866.42	7,988.40	[illegible]
16	Deferred Gas Cost Balance:										
17	Commodity	95,170.00	76,323.00	97,069.00	83,507.00	112,482.00	111,597.00	94,614.00	99,810.00	80,810.00	1,720,000.0
18	Supply Cost	96,366.04	110,887.02	148,854.88	179,615.71	240,088.38	239,205.84	201,806.61	212,208.61	138,366.07	$3,009,000.07
19	Transport	931.03	1,870.06	3,200.42	0.00	0.00	0.00	0.00	0.00	1,140.00	[illegible]
20	Total	97,296.62	110,657.88	149,293.20	179,615.71	240,088.38	239,205.84	201,806.61	212,208.61	134,438.00	$3,126,960.22
21	Cumulative Bal after T-...	28,000.84	28,199.26	29,880.65	11,201.79	83,296.58	44,007.10	29,579.81	44,000.14	35,929.49	
22	RECEIVED FROM SUPPLIER	91,811.5	74,465.9	92,215.8	83,507.0	112,482.0	111,597.0	94,079.8	99,810.0	81,318.6	1,880,187.6
23	DELIVERED TO CUSTOMER	65,795.6	85,175.4	100,874.5	96,795.2	91,291.0	104,214.1	94,614.3	92,190.2	80,714.6	1,882,816.8
24	IMBALANCE	3,986.05	10,709.48	8,458.94	13,288.09	(21,191.00)	(7,377.30)	0.29	(8,651.00)	7,109.39	4,656.6

Note: April - October (Mainline, volumes X EPNG fuel rate 4.5%), November - March (citygate, inclusive of fuel)

Exhibit NSP-2

Citizens Utilities Company
Northern Arizona Gas Division
Reconciliation of NSP Margin Sharing

Month/Year Per Informational Filing	Per Monthly Informational Filings Exhibit 1-A Line No.32	(a) From Exhibit NSP-1 NSP TOTALS Line 15	Difference	
Feb-96	($31,322.42)	($31,390.08)	($67.66)	(b)
Mar-96	($1,484.46)	($1,484.46)	$0.00	
Apr-96	($1,432.74)	($1,432.74)	$0.00	
May-96	($7,932.11)	($7,932.11)	$0.00	
Jun-96	($8,066.80)	($8,066.80)	$0.00	
Jul-96	($7,934.62)	($7,934.62)	$0.00	
Aug-96	($7,569.82)	($7,569.82)	$0.00	
Sep-96	($7,811.81)	($7,811.81)	$0.00	
Oct-96	($8,941.07)	($8,941.07)	$0.00	
Nov-96	($8,458.54)	($8,458.54)	$0.00	
Dec-96	($2,554.44)	($2,554.44)	$0.00	
Jan-97	($2,414.41)	($2,414.41)	$0.00	
Feb-97	($2,767.68)	($2,767.68)	$0.00	
Mar-97	($2,492.06)	($2,492.06)	$0.00	
Apr-97	($2,445.42)	($2,445.42)	$0.00	
May-97	[illegible]	[illegible]	$0.00	(c)
	[illegible]	($111,234.48)	($67.66)	

(a) There is a one month lag between the time of billing the customer and posting the NSP Margin Sharing to the Gas Bank.

(b) The first entry into the Gas Bank reflects the NSP Margin Sharing for the period October 31, 1994 through January 31, 1995. This was the first entry made to the Gas Bank subsequent to Decision No. 59289 which approved and established the criteria for the NSP. A minor difference of $67.66 exists between the NSP Margin Sharing credits made to the Gas Bank and that reflected on Exhibit NSP-1. A credit will be made in the May 1997 Gas Bank to reflect this adjustment.

(c) The May 1997 Monthly Informational Filing has not been filed with the Commission.

JAC-3

EXHIBIT JAC-3

BEFORE THE ARIZONA CORPORATION COMMISSION

PHOENIX ADM. OFFICE

RENZ D. JENNINGS
CHAIRMAN
MARCIA WEEKS
COMMISSIONER
CARL J. KUNASEK
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF CITIZENS UTILITIES COMPANY, NORTHERN ARIZONA GAS DIVISION, FOR AN ORDER APPROVING THE PROPOSED TARIFF FOR THE NEGOTIATED SALES PROGRAM.	DOCKET NO. E-1032-94-425
IN THE MATTER OF THE APPLICATION OF CITIZENS UTILITY COMPANY, NORTHERN ARIZONA GAS DIVISION, FOR A DECREASE IN ITS PURCHASED GAS ADJUSTMENT RATE, FOR THE ESTABLISHMENT OF A TRUST FUND ACCOUNT, AND FOR THE RECOVERY OF CERTAIN CAPACITY COSTS.	DOCKET NO. E-1032-95-079 DECISION NO. 59399 **OPINION AND ORDER**

Arizona Corporation Commission
DOCKETED
NOV 28 1995
DOCKETED BY SS

DATE OF HEARING: August 2, 1995

PLACE OF HEARING: Phoenix, Arizona

PRESIDING OFFICER: Lyn Farmer

IN ATTENDANCE: Marcia Weeks, Commissioner

APPEARANCES: Beth Ann Burns, Associate General Counsel, on behalf of Citizens Utilities Company;

Elaine Williams, Chief Counsel, on behalf of the Residential Utility Consumers Office; and

Janet Wagner, Staff Attorney, Legal Division, on behalf of the Arizona Corporation Commission.

BY THE COMMISSION:

On December 12, 1994, Citizens Utilities Company ("Citizens" or "Company") Northern Arizona Gas Division ("NAGD") filed an application with the Arizona Corporation Commission ("Commission") for approval of the proposed tariff for the Negotiated Sales Program ("NSP").

On February 21, 1995, Citizens NAGD filed an application with the Commission to approve a decrease in the Purchased Gas Adjustment ("PGA") rate to a negative $0.01 per therm, establish a trust fund account for the over-recovered bank balance, and permit cost recovery of 1,600 dekatherms ("Dth") of capacity for the Flagstaff, Arizona service area. By Procedural Order dated April 18, 1995, the above-captioned matters were consolidated. By Procedural Order dated June 7, 1995, a hearing in this matter was set for August 1, 1995. Upon Staff's Motion to Continue, the hearing was rescheduled to commence on August 2, 1995.

In Decision No. 59120 (June 8, 1995) the Commission ordered that the Company's PGA rate decrease from a positive $0.027 per therm to a negative $0.04 per therm until a final decision is reached in this proceeding, in order to slow the growth of the over-collected bank balance. The Commission also ordered a one-time refund of $5,000,000 of the over-collected bank balance.

On August 2, 1995, a hearing was held before a duly authorized Hearing Officer of the Commission in Phoenix, Arizona. At the conclusion of the hearing, the Hearing Officer took the matter under advisement pending submission of a Recommended Opinion and Order to the Commission. The parties filed their post-hearing briefs on September 14, 1995.

DISCUSSION

TRANSWESTERN CAPACITY CHARGES

In July 1990, the predecessor owner of the NAGD, Southern Union Gas ("SUG"), entered into a contract for firm capacity with the Transwestern Pipeline Company ("Transwestern"). The contract provided, in part, for a maximum daily quantity of 25,000 Dth of capacity: 10,000 Dth for delivery to the Kingman service area and 15,000 Dth for the Flagstaff service area. At the time of contracting with Transwestern, SUG had a full requirements contract with another pipeline, El Paso Natural Gas ("El Paso"). In 1991, Citizens acquired the NAGD and assumed the contractual relationships of SUG pertaining to the El Paso and Transwestern pipelines. Decision No. 57647 (December 2, 1991) approved Citizens and SUG's joint application for transfer of assets and Certificates of Convenience and Necessity, and also subjected Citizens to those terms and conditions previously imposed upon SUG by the Commission concerning its PGA mechanism.

At issue in Citizens' rate case filed May 3, 1993, was the propriety of passing pipeline charges from Transwestern through the PGA mechanism to ratepayers. The Commission determined in Decision No. 58664 (June 16, 1994) that "SUG's decision to contract with Transwestern for a second source of supply was prudent, but that full recovery of the Transwestern reservation charges is precluded since a portion of the contract quantity of 25,000 Dth represents unreasonable excess capacity." The Commission ordered that the Company exclude from its PGA as fixed reservation costs all Transwestern reservation costs charged for daily capacity in excess of 8,400 Dth for service to Kingman. The Commission also disallowed recovery in the PGA the daily capacity in excess of 1,460 Dth for service to Flagstaff "continuing until Citizens has installed distribution facilities to permit full access to the 15,000 Dth of Transwestern capacity at Flagstaff."

Subsequent to the issuance of Decision No. 58664, in November and December of 1994, the Company placed in service expanded distribution facilities which allow the Company to fully access the Transwestern capacity reserved for service to Flagstaff. Also subsequent to the issuance of Decision No. 58664, the Company entered into an agreement with Transwestern to amend its transportation contract to provide for maximum daily deliveries to Flagstaff of 16,600 Dth, an increase which represents the reassignment of 1,600 Dth of capacity previously assigned to Kingman. As a result of the amendment, the total contract quantity remains 25,000 Dth, with 8,400 Dth assigned to Kingman and 16,600 Dth assigned to Flagstaff.

On June 30, 1995, El Paso filed an application for a rate increase with the Federal Energy Regulatory Commission ("FERC") to recover deficiencies resulting in part from the step down of 300,000 Dth per day of Southern California Gas Company capacity. As a result of using the Transwestern capacity, Citizens has reduced its dependency on El Paso as reflected in its El Paso billing determinants being lowered by 22 percent, from 54,905 Dth to 42,599 Dth.[1] The Company projects that the El Paso reservation rate will increase by seventy percent, from $5.5260 to $9.4098. It is expected that the rates will go into effect, subject to refund, on January 1, 1996.

The Company believes that Decision No. 58664 authorized it to begin recovering the Flagstaff capacity costs in the PGA once it had installed the facilities allowing access to that capacity. In December 1994, the Company began including in the PGA bank balance all of the Transwestern capacity charges associated with Flagstaff, which has had the effect of offsetting (reducing) the Company's over-collected bank balance. As of May 1995, the Company had included $688,359.54 of these costs in the

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1 Although the billing determinants have been lowered, Citizens must still pay El Paso for the higher amount until the billing determinants are adjusted in El Paso's pending rate application.

PGA, and by year-end 1995, will have included approximately $1.5 million.

With this application, the Company requests full recovery of the Transwestern charges because it believes that the capacity is fully utilized to serve current customers, provides long-term economic benefit to current and future customers, and through diversification of supplies, has substantially improved the reliability of service and reduced dependency on El Paso.

Staff believes that even though Citizens now has access to all the Transwestern capacity, a portion of the total pipeline capacity currently under contract is not used and useful.[2] According to Staff, although the Transwestern contract has allowed Citizens to displace El Paso capacity, the cost of capacity purchased from El Paso has not and will not be reduced until the El Paso billing determinants are adjusted in the pending El Paso rate case at the FERC, and until such time, the capacity charges paid to El Paso and Transwestern are duplicative. Staff recommends that the current capacity surplus should be priced at El Paso capacity charges, and the cost of excess capacity should be shared equally between the Company and its ratepayers. According to Staff, this would result in a disallowance of approximately $50,000 per month. Staff and Citizens believe that once the El Paso billing demand is adjusted downward, then the "excess capacity" issue and disallowance should no longer exist. Staff recommends that this disallowance begin with December 16, 1994, the date that Citizens informed the Commission that the necessary Flagstaff distribution facilities were in place, and continue until such time as the El Paso billing demand decreases to approximately 42,599 Dth, which is anticipated to occur on January 1, 1996.

RUCO disagrees with the Company that Decision No. 58664 authorized the Company to begin including in the PGA all disallowed costs associated with the Transwestern pipeline capacity in the Flagstaff area upon completion of facilities necessary to provide access. RUCO concludes that the Commission has not authorized the Company to recover any of the disallowed Transwestern capacity costs, and, accordingly, the ratepayers are entitled to a refund of the full amount that has been recorded in the PGA. Furthermore, RUCO also argues that a decision to change the PGA rate to allow recovery of Flagstaff capacity in this proceeding would violate sound regulatory principles that preclude

[2] Staff calculates the excess capacity to be 18,110 Dth.

retroactive adjustments to established rates and would conflict with rulings in Scates v. Ariz. Corp. Comm'n, 118 Ariz. 531, 578 P.2d 612 (Ariz. App. 1978) and with Arizona's constitutional provisions regarding ratemaking.

We find that Decision No. 58664 did not automatically authorize Citizens to collect the Transwestern capacity costs in the PGA once it had established full access to the Flagstaff Transwestern capacity. Finding of Fact No. 23 found that because a portion of the contract quantity of 25,000 Dth represented unreasonable excess capacity, full recovery of the Transwestern reservation charges was precluded. Finding of Fact No. 28 agreed with Staff's recommendation to disallow 90.27 percent of the contracted capacity for Flagstaff. This 90.27 percent disallowance was to continue until the distribution facilities were installed. Once the facilities were in place, then the question of the amount of "excess capacity" needed to be addressed. This is the issue that must be decided in this proceeding.[3] We do not believe that a change in the amount of the disallowance would violate ratemaking principles or the Constitution because, as a practical matter, although Decision No. 58664 postponed the determination of the disallowance until the facilities were in place, it put everyone on notice that such a determination would be made and was considered during the setting of rates in that proceeding.

The real issue that needs to be decided is who should bear the cost of this additional capacity. The additional capacity has resulted in an increase in the total amount Citizens pays for capacity, but it has also resulted in reducing Citizens' dependence on El Paso by lowering the billing demand on the El Paso pipeline and thereby ameliorating expected El Paso rate increases; it has improved reliability of service and placed pressure on El Paso to improve service quality; and has provided the opportunity for obtaining lower cost gas supplies.

RUCO's recommendation to totally disallow the cost of the Transwestern capacity fails to recognize the benefits associated with having a second pipeline supplier. Given these benefits, it is not appropriate to disallow all the Transwestern capacity charges. After weighing these costs and benefits, we believe that the Staff recommendation to share the costs of the excess capacity between ratepayers and shareholders recognizes these benefits and represents a fair way to apportion these additional capacity

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[3] The term "excess capacity" is a misnomer in the sense that as long as Citizens has a full requirements contract with El Paso, any additional capacity from other sources is excess.

costs. We find that the appropriate costs to be shared are the capacity charges for the 15,140 Dth[4] priced at El Paso capacity charges from December 1994 forward until the billing demand is lowered as discussed above.[5] The PGA bank balance to be refunded should be adjusted to reflect the accumulated capacity disallowance from December 16, 1994 through December 31, 1995. If the billing demand is lowered on January 1, 1996, then no further "per therm" disallowance is necessary. If however, the billing demand does not decrease to 42,599 Dth or less on January 1, 1996, a per therm disallowance of negative $.0064 should be added to the transportation and variable demand cost component of the PGA. Any variance from the anticipated billing demand amount and/or effective date will require the Commission to re-evaluate at a later proceeding whether or not the entire 15,140 Dth should be disallowed from January 1, 1996 forward. We find that this is a reasonable and appropriate method to apportion the costs and accordingly, we will deny Citizens' request to allow it to offset the disallowances against any savings which may be realized in the future under the Transwestern contract.

PGA REVISION

Citizens has experienced several sizable fluctuations in its bank balance in the last few years that have resulted in both under-collections and over-collections. According to the Company, these swings in gas cost recovery cause rate instability for customers, earnings volatility for the Company, and result in rates that do not track the cost of service and do not send the appropriate price signals to customers. In order to make the PGA operate more effectively, both Staff and Citizens proposed revising the PGA. The proposed revisions will establish four PGA components: the commodity costs; the commodity cost bank balance; the transportation variable and demand costs; and the transportation variable and demand costs bank balance. The following proposed revisions were not opposed by any party:

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[4] This is the current capacity disallowance established in Decision No. 58664. Although there was some testimony concerning the appropriate service reliability standard, we do not believe that the evidence on the record is sufficient to make such a determination at this time, nor is such a determination necessary in this proceeding. However, Citizens should be aware of this potential issue in future proceedings and should note the discussion in Staff's Brief concerning this issue.

[5] All parties agreed that the capacity should be priced at El Paso rates. This results in a disallowance of approximately $45,000 per month.

Commodity Costs

The PGA rate would include a commodity cost component that would change monthly, based upon the rolling twelve month average of actual purchased gas costs.[6] The monthly report filed by the Company will include the cost and quantity of gas purchased during the most recent twelve months and the commodity component of the PGA rate will be adjusted after Staff completes its review and approval of this data. A triggering mechanism would precipitate Commission review if the monthly commodity rate varies from the base commodity rate by more than $0.03 per therm. A cost change that triggers this mechanism will become effective up to plus or minus $0.03 per therm and inclusion of the remaining portion of the change (i.e., the amount in excess of the trigger) will be deferred pending the outcome of the Commission's review.

Commodity Cost Bank Balance

The Company proposes to create a bank balance that would monitor the differences between the commodity costs included in the PGA rate and the actual commodity costs incurred. The commodity cost component of the PGA rate would be adjusted each month to reconcile that bank balance. There would be a two month lag in the reconciliation due to allowance for receipt, review, and recording of supplier invoices.[7]

Transportation Variable and Demand Cost

The treatment of transportation and demand costs would not change. These costs would continue to be included in the base cost of gas at the rate established by the Commission. As is currently the case, the Company will file a PGA case immediately following any known and measurable change in transportation costs that represent a 7.5 percent increase or decrease from the authorized transportation demand rate.

Transportation Variable and Demand Cost Bank Balance

The reconciliation of transportation demand costs will remain the same as under the current clause. The difference between the transportation demand costs included in the PGA and the actual

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[6] This rolling average would replace the current requirement of forecasting future gas prices.

[7] For example, the commodity cost bank balance for January would be reconciled in the March commodity cost component of the PGA rate.

transportation costs incurred by the Company will be maintained in a separate, transportation variable and demand cost, bank balance. The bank balance will accrue until the trigger point is reached, at which time the Commission will review and reconcile the accrued balance.

Although RUCO did not oppose the changes to the PGA, its witness did express reservations about customer understanding and response to the monthly change in the PGA rate. The Company indicated that it will undertake notification by bill insert and continue to inform and educate customers about the revised PGA mechanism. The revisions will require Staff to closely monitor the Company's monthly reports and verify the bank balance reconciliations. The revisions do not in any way modify or impede the Commission's ability to review these costs and bank balances during a PGA review or rate proceeding. The Company stated that should a PGA case or rate proceeding not otherwise occasion a review, it would not object to a requirement for an annual PGA review and hearing.

We agree with Staff and the Company that the proposed revisions to the PGA (including the monthly commodity rate and the commodity cost bank balance reconciliation) will allow customers to make more informed usage choices than with the current PGA mechanism's reliance on refunds and adjustments that do not correspond as closely in time to prevailing market conditions. Accordingly, we will approve these unopposed PGA revisions.

TREATMENT OF THE CURRENT BANK BALANCE

In its PGA application, Citizens requested that the Commission approve the establishment of an interest bearing trust fund account for the over-collected bank balance and that it be used to offset the effect of new rates expected to result from Citizens' now pending application for a rate increase. Citizens withdrew the proposal after the Commission issued Decision No. 59120 which ordered a five million dollar refund of the then over-collected bank balance.

The Company now recommends that if the Commission adopts the proposed PGA revisions, then, as of the date the new mechanism becomes effective, the existing balance be frozen and "zeroed out" by bill credit or refund to customers. The Company believes that this would help in the transition from an accrual account to the establishment and maintenance of separate bank balances for the commodity cost component and the transportation variable and demand cost component of the PGA.

We agree with the Company. As of January 1, 1996, the Company should establish the new separate bank balances, each with a balance of zero. The existing over-collected PGA bank balance, as adjusted for the Transwestern capacity disallowance, shall be refunded to customers through one-time checks to be issued no later than March 18, 1996, and should be prorated to customers based on usage for the twelve month period beginning January 1, 1995 through December 31, 1995. Citizens shall apply the amount of any refund owed as a bill credit for those accounts that became delinquent and were disconnected during the 12-month period; not issue a check for a refund less than $1.00; and withhold the estimated administrative costs of the refund, including the cost of the checks, processing costs, and mailing and postage expenses pending final recommendation and audit by Commission Staff.

NEGOTIATED SALES PROGRAM TARIFF

In its application in Docket No. E-1032-94-425, Citizens requests approval of a tariff to provide a new type of service, the Negotiated Sales Program ("NSP"). Through the NSP, Citizens would offer to obtain the gas supply requirements for its transportation customers. The application identified three primary purposes of the NSP, including: to provide a competitive alternative to current and future transportation customers in procuring gas supplies to meet their needs; to provide for lowering gas costs to firm sales customers through a sharing of the margins realized from NSP sales; and to provide the Company an opportunity to improve its earnings.

According to the Company, it will request each transportation customer to allow it to submit a bid to supply gas supply needs at the end of the term of its existing contracts. The Company will use its upstream pipeline capacity to transport NSP volumes, except during periods when capacity is needed to serve firm sales customers (the heating season from November through March). The Company will direct charge the NSP gas cost account for all variable costs billed by upstream pipelines and credit the gas bank account for fifty percent of the sales margin. The Company will maintain separate accounts for the NSP to record revenues, gas costs, and transportation expense.

Both RUCO and Staff supported the NSP tariff, with the imposition of several additional terms and requirements. Staff recommended that the minimum term of NSP contracts should be set at twelve months and the contracts should specify and document any alternative supply arrangements for gas deliveries between November 15 and March 15. Staff also recommended that in order to avoid a situation in which Citizens has an incentive to encourage customers to migrate from ordinary bundled service to NSP service, the Company should not be permitted to keep any portion of the margin on NSP sales that are made to a customer that has taken bundled service at any time during the last three years. Staff further recommended that the appropriate sharing of NSP margins should be reviewed in future base rate and PGA cases, and that the future disposition of NSP margins should be based on an assessment of the magnitude of NSP costs and benefits, and the extent to which the Company actually experiences exposure to a risk of loss.

Citizens did oppose Staff's recommendation to require minimum twelve month NSP contracts which specify and document alternative supply arrangements for gas deliveries during the heating season. The Company opposed Staff's recommendation that the Company should not be permitted to keep any portion of the margin on NSP sales made to customers that have taken bundled service during the last three years. According to the Company, it does not intend to encourage a sales customer to migrate to transportation service in hope of being selected as the gas supplier for the customer under the NSP tariff, as the Company states that it and its customers are better off if the customer retains sales service rather than NSP service. It is clear that both the Company and its customers do benefit if existing transportation customers become NSP customers, but it is not clear whether there would be an incentive for Citizens to encourage sales service customers to become NSP customers or whether such a move would benefit the Company and/or the non-NSP customers. Accordingly, we agree with Staff that at least initially, the Company should not be permitted to keep any portion of the margin on NSP sales made to customers who have taken bundled service at any time during the last three years. We also agree with Staff that the appropriate amount of "margin sharing" should be evaluated in future rate and PGA proceedings. The NSP sales margins, as discussed herein, should be credited to the transportation variable and demand cost bank balance.

RUCO recommended that for every sale of gas to an NSP customer under the tariff, Citizens should be required to assign an equivalent volume of gas to PGA customers at the same or lower price. RUCO also recommended that Citizens should provide assurance to the Commission that no cross-subsidization results from implementation of the tariff, and that the tariff should be implemented on a trial basis, for an initial two-year period.

The Company had no objection to RUCO's recommendation that it should submit a monitoring plan to Staff to ensure that no cross-subsidy occurs from sales schedule customers to NSP customers. The Company objected to RUCO's recommendation to " price match" volumes of NSP and PGA gas. According to the Company, it will not obtain an overall gas supply and then allocate a portion of those volumes to NSP sales, but will obtain contracts for separate and distinct gas supplies for each transportation customer. Since there will be no commingling of jurisdictional gas supplies with NSP gas supplies, the Company believes that no assignment or allocation of volumes is possible.

RUCO's recommendation has merit in that there is a direct incentive for the Company to find and procure the lowest price gas supply for NSP customers, while there is no corresponding direct incentive for the Company to find and procure the lowest price gas supply for PGA customers. However, given the Company's explanation of its procurement procedures, we agree with the Company that assignment or allocation of volumes is not possible. We believe that RUCO's concerns can be addressed through review and close monitoring of the Company's procurement practices. To that end, instead of implementing the tariff on a two year trial basis as recommended by RUCO, we believe that the NSP tariff, and Citizens' procurement practices should be reviewed two years from the date of this Decision.

In its NSP application, Citizens requested that the Commission exempt sales under the NSP from the regulatory assessment in order to place Citizens on a more equal basis with its competitors, who are non-regulated brokering firms. Staff recommended that the request be denied because Staff believes that the stature regulating assessments requires application to all jurisdictional revenues, which would include NSP sales. The Company did not pursue the request, and accordingly, we will not grant such an exemption.

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. Citizens is a Delaware corporation providing natural gas utility service to the public through the NAGD, in portions of Apache, Coconino, Mohave, Navajo, and Yavapai Counties, Arizona, pursuant to authority granted by the Commission.

2. On December 12, 1994, Citizens filed an application with the Commission for approval

of the proposed tariff for the Negotiated Sales Program.

3. On February 21, 1995, Citizens NAGD filed an application with the Commission to approve a decrease in the PGA rate, establish a trust fund account for the over-recovered bank balance, and permit cost recovery of 1,600 Dth of capacity for the Flagstaff, Arizona service area.

4. By Procedural Order dated April 18, 1995, the above-captioned matters were consolidated.

5. By Procedural Order dated June 7, 1995, a hearing in this matter was set for August 1, in Phoenix, Arizona and was subsequently rescheduled for August 2, 1995.

6. Notice of the hearing was published in a newspaper of general circulation in each county of the Company's service area.

7. The hearing was held as scheduled and no members of the public were present to make public comment.

8. SUG had a full requirements transportation contract with El Paso, and in July 1990, SUG entered into a contract for 25,000 Dth of firm capacity with Transwestern.

9. In 1991, Citizens acquired the NAGD and assumed the contractual relationships with El Paso and Transwestern.

10. Decision No. 58664 found that "SUG's decision to contract with Transwestern for a second source of supply was prudent, but that full recovery of the Transwestern reservation charges is precluded since a portion of the contract quantity of 25,000 Dth represents unreasonable excess capacity."

11. The Commission ordered that the Company exclude from its PGA as fixed reservation costs all Transwestern reservation costs charged for daily capacity in excess of 8,400 Dth for service to Kingman and also that capacity in excess of 1,460 Dth for service to Flagstaff "continuing until Citizens has installed distribution facilities to permit full access to the 15,000 Dth of Transwestern capacity at Flagstaff."

12. Subsequent to the issuance of Decision No. 58664, in November and December of 1994, the Company placed in service expanded distribution facilities which allow the Company to fully access the Transwestern capacity reserved for service to Flagstaff.

13. In December 1994, the Company began including in the PGA all of the Transwestern capacity charges associated with Flagstaff, which has had the effect of offsetting (reducing) the

Company's over-collected bank balance, and as of May 1995, the Company had included $688,359.54 of these costs in the PGA, and by year-end 1995, will have included approximately $1.5 million.

14. Decision No. 58664 did not authorize Citizens to recover the previously disallowed costs upon completion of the facilities prior to our determination of the amount of "excess capacity."

15. On June 30, 1995, El Paso filed a rate application with FERC and new rates are expected to go into effect January 1, 1996, subject to refund.

16. The issue of "excess capacity" will no longer exist if the billing determinants decrease to approximately 42,599 Dth as of January 1, 1996.

17. The Transwestern capacity has resulted in an increase in the total amount Citizens pays for capacity.

18. The Transwestern capacity has provided potential benefits to customers, including reducing Citizens' dependence on El Paso by lowering the billing demand on the El Paso pipeline and thereby ameliorating expected El Paso rate increases; improving reliability of service and placing pressure on El Paso to improve service quality; and by providing the opportunity for obtaining lower cost gas supplies.

19. Based on the circumstances presented herein, the Staff recommendation to share the costs of the duplicative capacity equally between the Company and the ratepayers is reasonable and appropriate.

20. The PGA bank balance should be adjusted to reflect the disallowance of fifty percent of the 15,140 Dth, priced at El Paso capacity charges, from December 16, 1994 to December 31, 1995.

21. The existing over-collected PGA bank balance as of January 1, 1996, as adjusted for the Transwestern capacity disallowance, should be refunded to customers through one-time checks to be issued no later than March 18, 1996, and should be prorated to customers based on usage for the twelve month period beginning January 1, 1995 through December 31, 1995.

22. The currently effective composite PGA recovery rate is $0.2600 per therm, which is comprised of the $0.3000 per therm base rate established in Decision No. 58664, and the PGA adjustment rate of negative $0.04 per therm established in Decision No. 59120.

23. The current PGA rate of negative $0.04 per therm should remain in effect, with the

transportation and variable demand cost component set at $0.084 per therm, and the gas commodity cost component set at $0.176 per therm, as adjusted for the twelve month rolling average commodity cost per therm sold.

24. If the El Paso billing determinants do not decrease as projected by Citizens on January 1, 1996, then an additional negative transportation and variable demand cost PGA factor of $0.0064 should be implemented.

25. The proposed revisions to the PGA are designed to allow customers to make more informed usage choices than are possible with the current PGA mechanism.

26. The proposed revisions to the PGA as contained in the Discussion herein, including the creation of two separate cost components to the PGA rate and two separate bank balances, should be adopted.

27. Citizens shall notify its customers by bill insert of the revisions to the PGA mechanism and shall inform and educate the customers about the effects of such a revision on a continuing basis.

28. As of January 1, 1996, the Company shall establish the new separate bank balances, each with a balance of zero, and shall include in its monthly PGA reports all activity affecting the bank balances.

29. Citizens shall file monthly PGA reports that include the cost and quantity of gas purchased during the most recent twelve months and should adjust the commodity component of the PGA rate only after Staff completes its review and approval of the data.

30. The PGA revisions adopted herein do not modify or impede the Commission's ability to review costs and bank balances during a PGA case or rate proceeding.

31. After the revised PGA mechanism has been in effect for one year, Citizens shall apply for a PGA review proceeding to be conducted and annually thereafter, unless such a review is conducted in conjunction with a rate proceeding or other PGA proceeding.

32. Citizens has proposed an NSP tariff whereby it would offer to obtain the gas supply requirements for its transportation customers.

33. Both Staff and RUCO generally supported the NSP tariff, with the imposition of several additional terms and requirements.

34. Staff's recommendation to require a minimum NSP contract term of twelve months, with the contract specifying and documenting any alternative supply arrangements for gas deliveries during the heating season, is reasonable and should be adopted.

35. Staff's recommendation that the Company should not be permitted to keep any portion of the margin on NSP sales that are made to a customer that has taken bundled service at any time during the last three years is appropriate at this time given the lack of evidence on the effect the migration from sales to NSP customers would have on the Company and its customers.

36. Staff's recommendation that the appropriate sharing of NSP margins should be reviewed in future base rate and PGA cases, and that the future disposition of NSP margins should be based on an assessment of the magnitude of NSP costs and benefits, and the extent to which the Company actually experiences exposure to a risk of loss, is reasonable and should be adopted.

37. RUCO recommended that for every sale of gas to an NSP customer under the tariff, Citizens should be required to assign an equivalent volume of gas to PGA customers at the same or lower price.

38. As explained by the Company, its procurement practices do not allow the assignment of equivalent volumes of gas to NSP and PGA customers.

39. RUCO recommended that Citizens should provide assurance to the Commission that no cross-subsidization results from implementation of the tariff, and that the tariff should be implemented on a trial basis, for an initial two-year period.

40. Citizens should submit a monitoring plan to Staff to ensure that no cross-subsidy occurs from sales schedule customers to NSP customers.

41. The Company's procurement practices should be closely monitored by Staff and Citizens should apply for a formal NSP review to be conducted no later than two years from the date of this Decision to ensure that the Company's procurement practices are reasonable and that the NSP program is appropriate and does not result in cross-subsidization.

CONCLUSIONS OF LAW

1. Citizens is a public service corporation within the meaning of Article XV, Section 2, of the Arizona Constitution.

2. The Commission has jurisdiction over Citizens and the subject matter of these applications.

3. Notice was provided in accordance with the law.

4. The Transwestern capacity disallowance as discussed herein is reasonable and appropriate.

5. The PGA revisions, as discussed herein, are reasonable and should be adopted.

6. The Company's proposed NSP tariff should be approved with the modifications and conditions contained herein.

7. The currently effective composite PGA recovery rate of $0.2600 per therm should remain in effect, with the transportation variable and demand cost component set at $0.084 per therm, and the gas commodity cost component at $0.176 per therm, as adjusted for the twelve month rolling average commodity cost per therm sold.

8. The existing over-collected PGA bank balance as of January 1, 1996, as adjusted for the Transwestern capacity disallowance through December 31, 1995, should be refunded to customers through one-time checks to be issued no later than March 18, 1996, and should be prorated to customers based on usage for the twelve month period beginning January 1, 1995 through December 31, 1995.

9. If the El Paso billing determinants do not decrease on January 1, 1996, then an additional negative transportation and variable demand cost PGA factor of $0.0064 should be implemented.

ORDER

IT IS THEREFORE ORDERED that Citizens Utilities Company, Northern Arizona Gas Division, shall adjust the Purchased Gas Adjustment bank balance to reflect the disallowance adopted herein for the Transwestern Pipeline Company capacity.

IT IS FURTHER ORDERED that the disallowance of Transwestern capacity adopted herein terminate on December 31, 1995, provided that Citizens Utilities Company, Northern Arizona Gas Division's billing demand on the El Paso system decreases to 42,599 Dth or less as of January 1, 1996.

IT IS FURTHER ORDERED that if the El Paso billing determinants do not decrease as contemplated herein, Citizens Utilities Company Northern Arizona Gas Division shall adjust the transportation variable and demand commodity cost component to reflect the continuing disallowance adopted herein for the Transwestern Pipeline Company capacity.

IT IS FURTHER ORDERED that the Purchased Gas Adjustment mechanism is revised effective January 1, 1996, consistent with the Discussion, Findings, and Conclusions contained herein.

IT IS FURTHER ORDERED that Citizens Utilities Company Northern Arizona Gas Division shall refund the amount of the over-collected PGA bank balance, as adjusted for the capacity disallowance adopted herein, as of January 1, 1996, in accordance with the Discussion, Findings, and Conclusions contained herein.

IT IS FURTHER ORDERED that the current PGA rate of negative $0.04 per therm shall remain in effect, with the transportation and variable demand cost component set at $0.084 per therm, and the gas commodity cost component set at $0.176 per therm, as adjusted for the twelve month rolling average commodity cost per therm sold.

IT IS FURTHER ORDERED that the Negotiated Sales Program tariff, with the modifications and conditions adopted in the Discussion, Findings, and Conclusions contained herein, is hereby approved.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN | COMMISSIONER | COMMISSIONER

IN WITNESS WHEREOF, I, JAMES MATTHEWS, Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 28 day of November, 1995.

James Matthews
JAMES MATTHEWS
EXECUTIVE SECRETARY

DISSENT
LAF/kjh

DECISION NO. 59399

SERVICE LIST FOR: CITIZENS UTILITIES COMPANY, NORTHERN ARIZONA GAS DIVISION

DOCKET NOS.: E-1032-94-425 AND E-1032-95-079

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Phoenix, Arizona 85007

Gary Yaquinto, Director
Utilities Division
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, Arizona 85007

DECISION NO. 59399

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JAC-5

EXHIBIT JAC-5

BEFORE THE ARIZONA CORPORATION COMMISSION

CARL J. KUNASEK
Chairman
JIM IRVIN
Commissioner
RENZ D. JENNINGS
Commissioner

IN THE MATTER OF CITIZENS UTILITIES COMPANY, NORTHERN ARIZONA GAS DIVISION – FILING FOR REVIEW AND MODIFICATION OF THE NEGOTIATED SALES PROGRAM TARIFF.

DOCKET NO. E-1032-97-345

DECISION NO. 60423

ORDER

Arizona Corporation Commission
DOCKETED

SEP 26 1997

DOCKETED BY jul

Open Meeting
September 25, 1997
Phoenix, Arizona

BY THE COMMISSION:

FINDINGS OF FACT

1. Citizens Utilities Company, Northern Arizona Gas Division (Citizens) is certificated to provide electric service as a public service corporation in the State of Arizona.

2. On July 3, 1997, Citizens filed for review and modification of the Negotiated Sales Program tariff (NSP).

3. On July 30, 1997, the Commission suspended the filing for 60 days to provide Staff with time to complete the necessary analysis.

4. Citizens requested a modification of the NSP tariff to allow Citizens to use its upstream capacity to transport gas for NSP customers during the winter months (November to March). The basis for Citizens' request is that terms of a recently approved El Paso Natural Gas Company (El Paso) rate settlement remove the need to restrict Citizens' usage of upstream capacity during the winter.

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5. The NSP tariff allows Citizens to compete with other gas suppliers to provide procurement services to Citizens' transportation customers. Margins from NSP sales are shared between Citizens and the ratepayers.

6. In Decision Number 59399 (November 28, 1995), the Commission barred Citizens from using its upstream capacity to transport gas for NSP customers during the winter months because it could increase Citizens' El Paso pipeline capacity costs, which are recovered from sales customers.

7. On April 16, 1997, the Federal Energy Regulatory Commission approved a settlement agreement in El Paso's rate proceeding (79 FERC 61028) which provides a fixed rate structure for interstate gas transportation until January 1, 2006.

8. The settlement agreement changed the way Citizens is billed for El Paso's service. Prior to the settlement agreement, Citizens' pipeline capacity reservation charges were determined by its peak day billing determinant, measured in Decatherms (Dth). As Citizens' peak day billing determinant increased, so did the corresponding capacity reservation charges.

9. Under the settlement agreement, Citizens' billing determinants, for the purpose of calculating capacity reservation charges, are set at 37,611 Dth (of which 34,544 Dth are allocated to the Northern Arizona Gas Division). However, because Citizens is a full requirements customer of El Paso, Citizens use of El Paso capacity is not constrained by the 34,544 Dth level. Therefore, for the term of the settlement agreement, Citizens' use of contract capacity for NSP customers should not incur any additional capacity reservation charges.

10. The possible exception is that Citizens could convert to being a contract demand customer, in which case any capacity beyond the 34,544 Dth level would incur new capacity reservation charges. Citizens' peak throughput is well above the 34,544 Dth level, so Citizens would incur significant additional capacity reservation charges if it converted to being a contract demand customer, especially in light of the growing demand for gas in the Northern Arizona Gas Division.

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11. Removal of the restriction on winter capacity usage enhances Citizens' ability to successfully bid to provide procurement services to its transportation customers. With the restriction removed, the customer's need to secure alternative transportation services, other than Citizens' capacity, is reduced.

12. Although the level of peak throughput will not change Citizens' billing determinants during the term of the settlement agreement, the level of peak throughput could be used in a future El Paso rate proceeding to set Citizens billing determinants after the settlement term is ended.

13. If NSP customers contribute to the peak day throughput, it is possible that sales customers would experience increased rates to cover the additional capacity costs resulting from the NSP customers. To avoid such a situation, Citizens has indicated that it will require NSP customers to utilize alternative transportation arrangements when volumes exceed the projected normal peak day throughput.

14. Citizens also stated that it will provide Staff with an annual report which documents each heating season's peak throughput day and whether any of Citizens' capacity was used for NSP customers.

15. Further, Citizens recommended including an NSP sales schedule as part of its monthly PGA informational filing.

16. Under the new situation created by the El Paso settlement agreement, removal of the winter restriction would assist Citizens in its retention of customers and could benefit ratepayers, through shared margins, if Citizens is able to provide procurement services to additional transportation customers.

17. Staff has recommended that the winter restriction on usage of Citizens' capacity be removed.

18. Staff has further recommended that the restriction on winter capacity be reinstated if Citizens converts to being a contract demand customer during the term of the El Paso settlement agreement.

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19. Staff has further recommended that Citizens file with Staff: an annual report on winter peak day transportation, an informational copy of all new NSP agreements Citizens enters into, and an NSP Sales schedule as part of Citizens' monthly PGA informational filings.

CONCLUSIONS OF LAW

1. Citizens is an Arizona public service corporation within the meaning of Article XV, Section 2, of the Arizona Constitution.

2. The Commission has jurisdiction over Citizens and over the subject matter of the application.

3. The Commission, having reviewed the application and Staff's Memorandum dated September 10, 1997, concludes that it is in the public interest to approve the filing.

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ORDER

THEREFORE, IT IS ORDERED that the NSP tariff filing be and hereby is approved.

IT IS FURTHER ORDERED that the restriction on winter capacity be reinstated if Citizens converts to being a contract demand customer during the term of the El Paso settlement agreement.

IT IS FURTHER ORDERED that Citizens file with Staff: an annual report on winter peak day transportation, an informational copy of all new NSP agreements Citizens enters into, and an NSP Sales schedule as part of Citizens' monthly PGA informational filings.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION

CHAIRMAN　　　　COMMISSIONER　　　　COMMISSIONER

IN WITNESS WHEREOF, I, JACK ROSE, Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of this Commission to be affixed at the Capitol, in the City of Phoenix, this 26 day of Sept, 1997.

JACK ROSE
Executive Secretary

DISSENT ______________________

CWD:BG:djg/CCK

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EXHIBIT JAC-6

OPEN MEETING ITEM

91

MEMORANDUM

[redacted] Corporation Commission
DOCKETED

SEP 11 1997

[redacted] BY

TO: THE COMMISSION

FROM: Utilities Division

DATE: September 10, 1997

RE: CITIZENS UTILITIES COMPANY, NORTHERN ARIZONA GAS DIVISION – FILING FOR REVIEW AND MODIFICATION OF THE NEGOTIATED SALES PROGRAM TARIFF (DOCKET NO. E-1032-97-345)

On July 3, 1997, Citizens Utilities Company, Northern Arizona Gas Division (Citizens) filed for review and modification of the Negotiated Sales Program tariff (NSP). On July 30, 1997, the Commission suspended the filing for 60 days to provide Staff with time to complete the necessary analysis. Citizens requested a modification of the NSP tariff to allow Citizens to use its upstream capacity to transport gas for NSP customers during the winter months (November through March). The basis for Citizens' request is that terms of a recently approved El Paso Natural Gas Company (El Paso) rate settlement remove the need to restrict Citizens' usage of upstream capacity during the winter. The NSP tariff allows Citizens to compete with other gas suppliers to provide procurement services to Citizens' transportation customers. Margins from NSP sales are shared between Citizens and the ratepayers.

In Decision Number 59399 (November 28, 1995), the Commission barred Citizens from using its upstream capacity to transport gas for NSP customers during the winter months because it could increase Citizens' El Paso pipeline capacity costs, which are recovered from sales customers. On April 16, 1997, the Federal Energy Regulatory Commission approved a settlement agreement in El Paso's rate proceeding (79 FERC 61,028) which provides a fixed rate structure for interstate gas transportation until January 1, 2006.

The settlement agreement changed the way Citizens is billed for El Paso's service. Prior to the settlement agreement, Citizens' pipeline capacity reservation charges were determined by its peak day billing determinant, measured in Decatherms (Dth). As Citizens' peak day billing determinant increased, so did the corresponding capacity reservation charges. Under the settlement agreement, Citizens' billing determinants, for the purpose of calculating capacity reservation charges, are set at 37,61 Dth (of which 34,544 Dth are allocated to the Northern Arizona Gas Division). However, because Citizens is a full requirements customer of El Paso, Citizens use of El Paso capacity is not constrained by the 34,544 Dth level. Therefore, for the term of the settlement agreement, Citizens' use of contract capacity for NSP customers should not incur any additional capacity reservation charges.

The possible exception is that Citizens could convert to being a contract demand customer, in which case any capacity beyond the 34,544 Dth level would incur new capacity reservation charges. Citizens' peak throughput is well above the 34,544 Dth level, so Citizens would incur significant additional capacity reservation charges if it converted to being a contract demand customer, especially in light of the growing demand for gas in the Northern Arizona Gas Division.

Removal of the restriction on winter capacity usage enhances Citizens' ability to successfully bid to provide procurement services to its transportation customers. With the restriction removed, the customer's need to secure alternative transportation services, other than Citizens' capacity, is reduced.

Although the level of peak throughput will not change Citizens' billing determinants during the term of the settlement agreement, the level of peak throughput could be used in a future El Paso rate proceeding to set Citizens billing determinants after the settlement term has ended. If NSP customers contribute to the peak day throughput, it is possible that sales customers would experience increased rates to cover the additional capacity costs resulting from the NSP customers. To avoid such a situation, Citizens has indicated that it will require NSP customers to utilize alternative transportation arrangements when volumes exceed the projected normal peak day throughput. Citizens also stated that itwill provide Staff with an annual report which documents each heating season's peak throughput day and whether any of Citizens' capacity was used for NSP customers. Further, Citizens recommended including an NSP sales schedule as part of its monthly PGA informational filing.

Under the new situation created by the El Paso settlement agreement, removal of the winter restriction would assist Citizens in its retention of customers and could benefit ratepayers, through shared margins, if Citizens is able to provide procurement services to additional transportation customers. Staff recommends that the winter restriction on usage of Citizens' capacity be removed. Staff further recommends that the restriction on winter capacity usage be reinstated if Citizens converts to being a contract demand customer during the term of the El Paso settlement agreement. Staff further recommends that Citizens file with Staff: an annual report on winter peak day transportation, an informational copy of all new NSP agreements Citizens enters into, and an NSP Sales schedule as part of Citizens' monthly PGA informational filings.

Carl Dabelstein
Director
Utilities Division

CD:BG:djg/CCK

ORIGINATOR: Robert Gray

EXHIBIT
JA-14
admitted

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Schedule G-4	Expense Allocation to Classes of Service
Schedule G-5	Distribution of Rate Base by Function
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Schedule H-1	Summary of Revenues by Customer Classification
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Exhibit JLH-11	Significant Workpapers

INTRODUCTION

Q. Please state your name, address and position.

A. My name is James L. Harrison. I am a management consultant and vice president with the firm of Management Applications Consulting, Inc., ("MAC") 2921 Windmill Road, Suite 4, Sinking Spring, PA 19608.

QUALIFICATIONS

Q. Please state your qualifications.

A. My qualifications are shown on Exhibit JLH-1. In summary I am a licensed professional engineer with an MBA. My career has spanned over 30 years. The last 23 of which have been concentrated on utility rate making activities, primarily cost of service and rate design.

SCOPE OF TESTIMONY

Q. Mr. Harrison, what is your responsibility in connection with this filing?

A. I am responsible for developing Schedules G and H, as set forth in the Arizona Corporation Commission's ("Commission" or "ACC") rule, R 14-2-103, summarizing the class cost of service study, billing units, rate design and revenue proof for this filing. My tasks have included developing the adjustments to test year billing determinants, preparing the accounting cost of service study and developing the proposed rates and tariff revisions. I have made separate sets of calculations for the Northern Arizona Gas Division ("NAGD") and the Santa Cruz Gas Division ("SCGD"), however I have presented my results on a combined basis wherever possible.

Q. Please outline the organization of your testimony and exhibits.

A. My testimony will first discuss the development of appropriate billing units for each rate class, then how I developed the cost studies and how I used them to design rates. I will then discuss updates to the tariffs including revisions to the line extension policies and miscellaneous service fees.

In the course of my testimony I will sponsor two schedules, G and H, and ten additional exhibits. Exhibit JLH-2 details my weather normalization calculations for the test year. Exhibit JLH-3 shows the development of the weather normalized billing units employed for cost of service and rate design purposes. The resulting billing units are provided in Schedule H-5. Exhibit JLH-5 shows the development of the more significant allocation factors used in the accounting cost study. Schedule G, consisting of 7 schedules, contains the accounting cost of service study results at the actual and claimed rates of return. Exhibit JLH-4 tabulates the results of the cost studies using various alternative allocation methods see page 22 line 27. The remainder of Schedule H and Exhibit JLH-6 show the results of my proposed rate design. Exhibit JLH-7 summarizes my analysis of costs to provide miscellaneous services. Exhibit JLH- 8 tabulates Miscellaneous Service Fees for other utilities. Exhibit JLH-9 reflects the revenues to be derived from my proposed miscellaneous service fees. Exhibit JLH-10 contains a redlined set of tariffs. Finally, Exhibit JLH-11 provides the more significant workpapers generated in the preparation of this filing.

WEATHER NORMALIZATION

Q. What is the purpose of a weather normalization adjustment?

A. For the purposes of rate making, the test year must represent typical or normal circumstances. As with all gas distribution utilities, the Company's sales are extremely weather sensitive. Even small variations in weather can have a material impact on the sales and revenues of the Company. The weather normalization adjustment is targeted to identify the change in sales and revenue that would have resulted if the actual weather in the test year had been what I consider "normal".

Q. How do you define normal weather?

A. Industry experience has shown that heating use is the largest single use of natural gas. As such, consumption varies directly with customer heating needs. Heating requirements are minimal when average daily temperatures exceed 65 degrees Fahrenheit. Consequently, the industry has developed the unit of "heating degree days" as a variable to predict heat load. Heating degree days ("HDD") are computed daily as the positive difference between 65 and the average daily temperature. For example, a very cold day with an average temperature of 0° F. would have 65 HDD's. The Company maintains a historical database of daily HDD data for its service territory. Using this database, I defined normal weather as the anticipated heating degree days, if weather were equal to the average of the heating degree days occurring over the last 10 years. The Company employs four weather stations in the NAGD and a single weather station in SCGD. For NAGD, I reduced the four daily weather readings into a single, load-weighted average daily HDD. Then I separately developed normal weather for the two divisions. I summed the most recent 10 years of daily data and then averaged each month to derive the expected monthly heating degree days in a normal year. The use of 10 years is consistent with the period employed by Southwest Gas in its recent rate proceeding before the ACC.

Q. Please summarize your weather normalization calculations.

A. I have summarized the weather normalization calculations on Exhibit JLH-2. The first four pages show monthly test year data for each class under study for 2001, including number of bills, sales in therms, Total Revenue billed and PGA Revenues included in the total. These pages include two revisions to the per-books data. First, I removed the New Service Area Multiple ("NSAM") revenues applicable to certain customers in the NAGD. Since the NSAM rate expired at the end of the test year in accordance with an ACC order, the reduction in revenues is a known and measurable change to test year revenues. Second, I have included a minor revision to the per-books numbers to reflect several large billing adjustments made to Rate 32, the Large Industrial Rate class, and Rate 42, the Large Public Authority Rate class. These adjustments were necessary in order to produce an accurate weather normalization adjustment. For these large customers, the billing process employs estimated bills in order to permit a timely closing of the books each month, followed by a cancel and re-bill at a later date. The cancel and re-bill often occurs in another month. As a result of this process, the test year recorded sales included some sales from the prior year and some adjustments that were not corrected until 2002. The calculation of an accurate weather normalization adjustment requires that sales and weather data be well synchronized. In order to tabulate an accurate sales figure in each billing period, the billings were restated to the actual consumption that took place in the period. Had I excluded these adjustments the weather normalization calculation for the class would have been distorted. The details supporting these adjustments are shown in my work papers, Exhibit JLH-11.

Monthly customer billing data is recorded on a billing cycle basis, as the meters are read throughout the month. For example, consider the January 2001 billing cycles. Meters read at the beginning of the month include consumption occurring in both December and January. Thus, the billing cycle degree days must be a weighted average of the daily degree days occurring in December 2000 and January 2001. Based on the scheduled read dates for each billing cycle throughout the year, the degree days each day, and the number of meters read for each class in each billing cycle, I determined the number of days and number of degree days for each billing cycle. This information, I was able to compute the billing period degree days for each month and for each rate class. The details of these calculations are shown in my work papers, Exhibit JLH-11. As an example, I calculated that 49.6 % of the residential class's metered and billed consumption for January was consumed in January, while the remainder was used in the previous month. Using these results, I computed weighted average actual and normal degree days for each billing month. This same process was repeated for all sales and transportation categories. Note that the Company's meter reading schedule results in larger customers and Company use meters being read toward the end of the month. As a result, customer consumption in the large rate classes is metered primarily in the current month with less of a lag than experienced with the residential and small classes.

Q. Could you describe the weather normalization calculations?

A. Exhibit JLH-2, page 5, shows an example of the class-specific computation of sales and revenue adjustments resulting from weather variations, in this case Residential Service, Rate 10. My calculation employs a very common algorithm that I call the "Base Load and Heating Load Method". This approach assumes that the level of usage occurring in the warm summer months, called "base load" is invariant with weather conditions throughout the year. Base load on a per customer basis equals the average use per customer in the months of July and August. I have refined this method slightly in those cases when July usage was substantially below August. I have found that base use may be understated due to plant shutdowns over the week of July 4th. To address this fact, when July usage was very low I used the average of August and the lower of June or September sales to establish an appropriate base load. Heating load each month is computed as the difference between total billed sales and the computed base load. Monthly heating factors reflecting the variation in sales to degree days are computed by dividing the heating load by the actual billing cycle degree days to derive the actual unit heat load per degree day. This figure was then multiplied by the temperature departure from normal to develop a weather adjustment. In some months, actual weather was warmer than normal while in others it was colder. In total, the year was slightly warmer than normal resulting in about a 1% increase to billing month sales.

Q. Did you weather normalize all rate classes?

A. No, I performed a consistent set of adjustments for all rate classes where sales were directly related to heating requirements. Regressing calendar month sales versus degree days, I found most rate classes had statically significant correlations, indicating a direct relationship between degree days and load. Of the classes without strong correlations, two were air-conditioning, one was gas lights, and the others were industrial classes. For each of these exceptions, loads varied only slightly from month to month and were not appreciably greater in the winter period.

Q. How did you derive the revenue adjustment?

A. This calculation is shown on the right side of the calculations on Exhibit JLH-2, page 5. Since several of the Company's present rates are of a declining block nature, the volumetric weather adjustment was multiplied by the price of the rate block serving the average usage in that month. Exhibit JLH-2, page 6, presents the weather normalized sales volumes under present rates. Page 7 shows the base revenues under normal weather conditions. Page 8 shows the weather normalized PGA revenues. Supporting calculations for all classes are included in the workpapers.

Q. Thus far you have described the adjustment of heating loads due to variations in actual heating degree days. Did you perform a similar calculation to weather normalize the air conditioning class for differences between actual cooling degree days and normal?

A. No, I did not. While there is some theoretical merit to this calculation and while data is generally available, the amount of natural gas that is used for air conditioning is so small that it does not merit consideration.

BILLING DETERMINANTS

Overview of Billing Determinants

Q. Please summarize your process to develop billing units for rate design purposes.

A. The first step was to perform the weather normalization calculation just described. The second step was to test the per books data to verify its reasonableness for rate design purposes. The third step was to compute calendar month sales for each class, to reflect the gas volumes that were consumed each month rather than simply those that were billed each month. The final step was to make customer annualization adjustments, i.e., adjusting the monthly billing determinants to reflect the billing units that would be expected if the number of customers at the end of the test period had been there for the entire year.

Reasonableness of Per Books Data

Q. How did you evaluate the overall accuracy of the Company's billing system?

A. In order to assure myself that the per books sales data was consistent with the Company's recorded revenues, I prepared a revenue proof at present rates, labeled as Schedule H-3 Unadjusted, comparing computed revenues from the billing determinants with the per books revenues. To make this comparison, I started with the bill count and recorded sales for each class and for each month. However, since the Company's rates are not flat, I had to estimate the distribution of sales between blocks. This was accomplished with the aid of a bill frequency produced by the Company's billing system indicating the sales by block. I have tabulated the per books sales volumes on Schedule H-5. The billed revenues are computed on

Schedule H-3 by multiplying the per books billing determinants by the tariff rates. These numbers were compared with the per books revenues on Schedule H-1. Dividing the booked revenues by the billed revenues resulted in the booked-to-billed adjustment ratios, which are shown at the right. In each instance the booked to billed ratio was close to unity. In total, the difference between the two was less than a fraction of 1%.

Computation of Calendar Month Sales

Q. Please describe your next step toward developing the billing units for the test year.

A. As with virtually all gas utilities, Citizens produces customer bills most working days of the month. Each customer is assigned to one of 21 different billing cycles. As an example, the NAGD's first billing cycle in January contains 5,953 customers. In the test year, these meters were read on January 2 resulting in bills mailed a few days later. The metered consumption for this cycle of customers consists of all that consumption since the previous meter read, from December 4 through January 1. The Company records these sales and revenues as January billing month revenues despite the fact that the large majority of all consumption in this billing cycle occurred in December of 2000. Of course, some customer's billing cycles coincide much more closely with the calendar month. For example, cycle 21, consisting of large customers served on the Company's T-1 Transportation Rate are tele-metered and read at the conclusion of the month. All of their recorded sales occur in the calendar month. This greatly simplifies the administration of the transportation rate and allows the Company to bill consumption that exactly corresponds to the calendar month.

The Company's revenue requirements are determined on an accrual accounting basis for the calendar year 2001. Thus, if rate design and cost allocation activities are to correspond to the test year costs, they must be restated to reflect calendar month sales not billing month sales, i.e., the consumption that actually took place in the month, rather than the consumption that was billed in the various billing cycles throughout the month. In order to develop calendar month sales, I made a complex set of calculations to segregate each month's billed sales into consumption occurring in the current month and consumption occurring in the prior month. Making this calculation for the billings in 13 months ending January 2002, I was able to compute each class's calendar month sales in the test year. The details of these calculations are shown for each division in my work papers, Exhibit JLH-11, and summarized on Exhibit JLH-3, page 1.

Q. Please describe these calculations.

A. Using the dates of each billing cycle read date, the number of meters read in each cycle by class, and the degree days each day, I was able to compute an allocation of billed sales to each calendar month in two parts – base use and heating use. Recall from my discussion of the weather normalization adjustment, that I determined the base use for each customer class that is invariant with heating degree days and the heating use that is directly proportional to heating degree days and invariant with the number of days in the billing period.

First, I computed the number of billing month days occurring in the calendar month for each billing cycle. Weighting these statistics by the number of meters billed in each cycle, I computed the percentage of billing month days in the current calendar month. From this, I segregated the base load use between the current calendar month and the previous calendar month. Next, I performed a similar calculation using degree days. Computing the degree days in each billing cycle, the portion of them occurring in the calendar month and weighting them by the number of customers in each cycle, I computed the percentage of each billing month's heating use occurring in the current calendar month. As an example, I computed the January calendar month sales as:

		Base Use		Base Use		Heating Use		Heating Use
Sales in Calendar Month January	=	Billed In	+	Billed In	+	Billed In	+	Billed In
		January		February		January		February

The results of these calculations, shown in Exhibit JLH-3, pages 1, 2 and 3, tabulate weather normalized calendar month sales, base revenues and PGA revenues, respectively, for each month and for each customer class.

Q. Please describe the customer annualization adjustment.

A. The customer annualization adjustment restates the billing determinants for the test year as if the customers on the system at the end of the year, December 2001, were present for the entire test year. The year-end customer adjustment was straightforward. For each rate class and for each month, the number of customers, the sales and the revenues were adjusted on a pro rata basis multiplying by the ratio of year-end customers to current month customers. Exhibit JLH- 3, page 4 through 8, shows the number of customers each month, the percentage adjustment applied by class and month, the resulting sales volumes, the resulting base revenues and the resulting PGA revenues, respectively.

Q. Please describe your derivation of billing units applicable to miscellaneous service fees.

A. As I will discuss later, I have proposed a number of minor changes not only to the prices but also to the very services to be charged under the category of the miscellaneous service fees. In order to estimate billing determinants, I began by tabulating the test year revenues for each category of existing fee and dividing by the rates in effect to compute the number of events billed. The resulting revenues for the two divisions are shown in total by category on Exhibit JLH-9, page 1. Monthly revenues and billing units are shown on Exhibit JLH-7. In several instances, I relied on the estimates provided by NAGD operating personnel as to the number of events for newly created or revised miscellaneous services. This was more problematic in the SCGD, where present tariffs define relative few miscellaneous services.

Q. How did you estimate miscellaneous service fee billing units for the SCGD?

A. The SCGD has some of the same miscellaneous service fees found in the NAGD. Where fees currently exist, I performed the same calculation, dividing revenues by rates to get billing units. In those instances where the service fee is new to the SCGD, I employed the experience in the NAGD to estimate the number of events to be billed in SCGD. My calculation was simple; I multiplied the NAGD number of billing events by the ratio of SCGD customers to NAGD customers.

Q. Did you make any further adjustments to the billing data?

A. No.

ACCOUNTING COST OF SERVICE STUDY

Overview of Process

Q. Would you briefly define an Allocated Cost of Service Study?

A. The cost to serve the customers of any utility company consists generally of operating expenses and return on investment. For a historical test period, these costs are on record and the overall cost to serve the collective customers of the utility may be readily established. On the other hand, the unique cost to serve customers of the various service classifications is much less apparent. Costs can vary significantly among customer classes depending upon the nature of their requirements and the facilities necessary to serve them. The purpose of an Allocated Cost of Service Study is to assign or allocate each relevant component of cost on an appropriate basis in order to determine the proper cost to serve the respective classes. The result is a cost matrix displaying the detailed costs of serving each customer class for each cost category.

Q. Please describe the procedure that you used in preparing your Allocated Cost of Service Study.

A. Through the application of a computerized microcomputer cost model developed by MAC specifically for Citizens Communications - Arizona Gas Division's ("AGD") operations, it was possible to treat each element of Rate Base, Revenue, and Operating Expense in detail and to assign or allocate each item to customer classes. I performed separate cost studies for the NAGD and SCGD and then summed their results in order to depict the costs to serve the entire AGD. The complete process is reflected in Schedules G-3 and G-4 and mirrors the total cost to serve, as presented by Mr. Mason in his testimony. The detailed cost studies for each division are included in my workpapers, Exhibit JLH-11.

Q. Please summarize Schedule G.

A. Schedule G contains seven separate schedules. Schedules G-1 and G-2 summarize the cost allocation studies' results. The first study, labeled Schedule G-1, summarizes the results of the conventional cost of service study at present rates. Schedule G-2 shows similar information at proposed rate levels. Schedule G-3 shows the allocation of rate base, while Schedule G-4 shows expense allocation. Schedules G-5 and G-6 tabulate the functional make-up of rate base and expense, respectively and provide unit cost information. Finally, Schedule G-7 presents all of the allocation factors used in the NAGD and SCGD cost studies including labor.

Description of Cost Model

Q. How does the computerized cost model operate?

A. The cost model is simply a cost matrix. The vertical dimension of the study consists of the costs to serve as provided by the Company. The development of the cost of service study begins with rate base and continues with revenues, operating expenses, taxes, and the computation of a labor allocator. The cost model includes three additional sections, a summary of costs to serve, a list of the allocation factors employed in the study and a revenue requirements section.

The horizontal dimension consists of customer classes. Since the customer classes cannot all fit on a single page, several sub-pages are required to list all customer classes.

Each page, starting with page 1 has an important column immediately preceding the numerical data marked "ALLOC", an abbreviation for ALLOCATOR. The ALLOC column contains an acronym to indicate the allocation factor used to allocate the costs shown in the Total Company Column to individual customer classes. A tabulation of these allocators in absolute form, typically total dollars, volumes, or as a percent of total, has been provided as Schedule G-7. For ease of understanding, Schedule G-7 also shows these same allocations on a percentage basis.

Using these allocation factors, costs shown in the Total Company column are assigned to each customer class shown on the horizontal of the cost study. The cost study results can be replicated with calculator.

Classes of Service in the Cost Model

Q. How did you establish the rate classes in structuring your cost model?

A. In general, I set up one column in my cost study for each existing rate class. However, there were some exceptions. I excluded the NSAM class, since the rate had expired, and merged all NSAM customers into their native classes. I also merged the customers in the transportation class, Rate Schedule T-1, into their native classes, and then excluded the T-1 class.

Q. If you merged the transportation customers with the sales customers of similar characteristics, how will you be able to differentiate between the costs for transportation service and for sales service?

A. The cost study separately tracks delivery costs, which are common to both sales and transportation customers, and gas supply costs, which are incurred by sales customers only.

Allocation Methods

Q. Would you please tell us how you chose allocation factors for your cost study?

A. In the cost allocation process, I attempted to determine the intended use of specific plant investments or expenses and then examined the specific use of these assets in the test year. Then I developed an external allocator or created an internal allocator to assign these costs appropriately to customer classes.

Q. Could you be more specific, perhaps providing an example demonstrating the difference between an external and internal allocator?

A. An external allocator is a relationship between a cost and its cost causative factor. As a simple example, if the costs in account 903 to print and mail a bill are the same for all customers regardless of class, then billing costs are simply the average cost per bill multiplied by the number of bills for each class. In this instance, number of bills is an external allocator for the billing costs in the test year.

An internal allocator is simply a computed figure developed within the cost model and used to allocate other costs. As an example, consider property taxes. It would be virtually impossible to develop an external allocator relating property taxes to customer classes; however, we know that property taxes are a function of plant investment. So if we can allocate each item of plant investment to customer classes using external allocators, we can develop an internal allocator consisting of the sum of all of these various plant items and use it to allocate property taxes to classes.

Q. How did you select allocators for production costs?

A. I examined two alternative approaches to the allocation of production costs – a simple annual commodity allocation and a combination of design day demand and monthly commodity allocation.

The first allocation method is consistent with the Company's gas pricing mechanism in effect during the test year. The Company priced gas by embedding a fixed rate, 25 cents per therm of gas cost in the NAGD and 38.84 in the SCGD in each sales rate schedule. In addition, the purchased gas adjustment clause recovered variations in gas costs uniformly on a per therm basis among customer classes. The pricing mechanisms did not distinguish between demand and commodity costs. Thus, the commodity allocation simply allocates total gas supply costs to customer classes in proportion to their weather normalized and year-end customer adjusted calendar month sales in the test year. This allocator was developed as part of the billing determinants.

For most utilities, supply costs consist of supplier charges and pipeline charges. At the present time, suppliers are generally willing to provide variable price rates only; they do not include a demand reservation charge.

The same is not true of pipelines. Most Federal Energy Regulatory Commission ("FERC") approved pipeline tariffs consist of a reservation charge as well as a volumetric charge. The reservation fee paid by transporters is a monthly fixed charge based on the Maximum Daily Quantity ("MDQ") the pipeline is obligated to reserve for delivery multiplied by the FERC-approved rate. The variable charge, normally a much smaller portion of the total cost, is billed on a volumetric basis. For utilities such as Citizens, with no manufactured gas capability down stream of its city gate, the Company must establish its MDQ based on the maximum demand expected of it sales customers.

In the test year, the Company delivered the majority of its purchased commodity gas through El Paso Natural Gas Company ("El Paso"), an interstate pipeline, under a full-requirements ("FR") transportation, which included a fixed component for demand reservation that did not vary in accordance with the maximum demands established by the Company. The demand reservation fee, over $5 million per year, was fixed regardless of the level of demand imposed on the transmission system. The utility was placed in the enviable position of having no incremental fixed transportation supply costs. This somewhat unusual pricing arrangement may not continue into the future.

As discussed in Mr. Cogan's testimony, a recent FERC order mandates the conversion of the Company's El Paso FR contract to fixed entitlement demand contract. Instead of receiving all requirements service, the Company will be required to contract for a specific MDQ. The MDQ must be established at the highest level of load and in anticipation of the coldest weather the Company can reasonably expect to serve. Typically, the predicted peak day load is that load expected on the coldest day on record or over the last few decades. The load under these extreme day weather conditions is termed the "design day demand".

Therefore, under this second allocation method, the fixed costs that are included in the current supply charges are allocated on the basis of the estimated design day demands of each customer class. The development of the design day allocation factor is summarized on Exhibit JLH-5, beginning on page 46. Commodity costs are allocated monthly on the proportion of sales consumed by each class in that month. Because gas costs are normally lower in the summer than in the winter, commodity costs tend to be higher for classes whose load is predominately in the winter. Exhibit JLH-5 pages 34, 35, 39 and 40 show the allocation of each division's gas costs using the two alternative cost allocation methods.

Please note that, for these calculations, I have employed the pro forma monthly gas costs computed by Mr. Cogan, the Company's gas supply witness, based upon the calendar month, weather normalized, year-end customer adjusted sales that I computed. Mr. Cogan's calculations of gas cost add fuel and lost and unaccounted for gas to the calendar month, weather normalized, year-end customer adjusted sales shown on Exhibit JLH-3.

RATE BASE ALLOCATION

Q. Mr. Harrison, please describe the allocation of rate base to customer classes.

A. Rate base allocation is shown on Schedule G-3, pages 4 through 8 of the cost of service study. Distribution mains investment is the majority of plant in service; therefore its allocation is critical. Distribution plant allocation factor ("DISTR") is the capacity allocation factor used for the allocation of distribution plant capacity-related costs, such as distribution land and land rights, measuring and regulating station equipment and mains. This allocator is based on the Proportional Responsibility Method, whereby the normalized monthly system loads carried by the distribution system are weighted so that costs are assigned to months based on the variation of sales from peak to off-peak months.

Q. Have you provided any information to describe the nature of the Proportional Responsibility Method?

A. Yes, Exhibit JLH-5 beginning at page 50 shows the development of the Proportional Responsibility Allocator for each division. In addition, I have included a brief discussion of the method including the original article, published in 1973 by Mr. Gary Grainger in "Public Utilities Fortnightly", in my workpapers, Exhibit JLH-11. In the past MAC has employed the Proportional Responsibility Allocator in its cost studies for over a dozen gas distribution utility rate cases in seven states.

Q. Did you consider any other allocation methods for distribution plant?

A. Yes, the Company's investment in capacity-related distribution equipment dominates the rate base investment and warrants some level of sensitivity study. Therefore, I have examined several other alternative allocation methods and tabulated the results on Schedule Exhibit JLH-4. For this analysis, I considered several additional allocation methods – design day demand only, only, and combinations of design day demand and commodity send out requirements methods using a 50/50 weighting, a 60/40 weighting and a 40/60 weighting of those two methods. The results indicate that the Proportional Responsibility Method, while not as extreme as a design day allocation, recognizes the higher costs of serving loads at time of peak.

Q. Did you attempt to segregate the investment in mains or services between the demand and customer components?

A. No. Some costs analysts recognize that these investments are joint, in an economic sense, and attempt to segregate costs between demand and customer components. The two most common methods are the minimum system and zero-intercept methods. While there may be some theoretical attraction to these methods, my experience has shown that they are extremely subjective. The results can be strongly influenced by the individual judgment of the cost practitioner. Rather than engage in such speculation, I have made the simplifying assumption that all investment in mains is capacity-related, and all service investments are customer-related.

From a practical standpoint, this approach assigns slightly less costs to the customer component. A review of the Company's current customer charges compared to the customer costs to serve indicated on Schedule G-6 reveals that current customer charges are a small fraction of customer costs. If I were to perform a zero-intercept or minimum system study, a portion of mains investment would be assigned to the customer component. The customer costs to serve would be even greater than I have proposed, causing the ratio of customer charges to customer costs to decline even further. Recognizing that customer charges cannot be raised to the full level of customer costs, the need to segregate mains and services investments at this time is moot.

Q. What are the customer-related allocation factors included in your cost study?

A. Customer-related plant items were allocated using "CUST"-prefixed allocators for services, meters, and other such customer-related items. These factors, taken from the Company's continuing property records, general accounting records, and any other available sources, serve to allocate the specific customer-related costs incurred for each customer class.

With the exception of mains, the services investment in Account 380 is the largest rate base account. However, as with most utilities, the Company's continuing property records provide little insight into the proper allocation of these costs to customer classes. Using a combination of engineering estimates and accounting records, I was able to develop a services allocator that recognizes the differing initial costs of constructing services for customers in the various customer classes and that also recognizes the sharing of services common to some classes.

Q. Could you please elaborate on the first item, differing initial costs?

A. This is the most basic difference among classes--the initial costs of installation. These costs are determined by the length of the service, its material, whether plastic or steel, the pressure available in the mains serving the customer, the diameter necessary to provide the requested volumes, and the customer contribution, if any. To address this question I had the Company provide a range of typical service installations as a function of pipe diameter. Estimated costs for new services to serve large and small customers were separately computed.

Q. Please discuss the second factor affecting service costs, sharing of services.

A. The second factor is services per customer. This factor relates to the fact that not all customers require a service. For example, one service to an apartment complex, office complex or strip mall can serve several customers. I assumed that only small customers shared services. I assigned one service to each large customer and subtracted the number of assigned services from the total number of services shown in the Company's property records. I divided the number of remaining services by the total number of residential and small customers to develop an appropriate service per customer ratio for these classes.

The final step was to develop the services allocator. I multiplied each class's estimated cost per service by the services per customer ratio and the numbers of customers in the class. The resulting values were summed and prorated by a uniform percentage to match the original cost investment shown in the Company's books.

Q. How did you allocate meters, regulators and installations?

A. I employed the same general approach used for services. I developed a replacement cost new estimate, adjusted it for meters per customer and then pro rated by results to match the original cost investment shown in the Company's books. Since the meter and regulator investment is segregated in the Uniform System of Accounts between larger industrial meters and regulators and small ones, the allocators were developed separately for the large rate classes and the small ones. The complete calculations for the services and meters allocators are included in my work papers, Exhibit JLH-11.

Q. How was general plant allocated on Schedule G-3, page 5 of the cost study?

A. All items of general plant were allocated on an internally generated labor allocation factor ("LABOR") based on labor expensed and capitalized for each account in the test year. Each Operations and Maintenance ("O&M") function was examined to determine the labor portions of expense included. The labor portions of these costs were allocated separately in the same manner as the total accounts were allocated. Similarly capitalized labor costs were assigned to classes on the same basis as the plant function. The allocated labor costs were then subtotaled by class to arrive at the composite allocation factor LABOR. The detailed development of the LABOR allocator is provided on Schedule G-7.

Q. How was each account of reserves for depreciation allocated?

A. Each account of reserves was allocated on the subtotal of the corresponding allocated costs of its respective plant item.

Q. What other elements of rate base were included in your study?

A. Net plant was increased for materials and supplies. The deductions from net plant included a cash working capital component developed in the Lead/Lag study, customer advances, a reserve for deferred federal income taxes, and customer contributed capital. Each item was allocated on the most appropriate allocation factor.

OPERATING EXPENSE ALLOCATION

Q. How were operating expenses allocated?

A. The allocation of O&M expenses follows the method by which these expenses were incurred. Therefore, the plant-related capacity expenses are allocated using the same allocators used for their associated plant investment.

Q. How were the gas costs allocated?

A. Gas costs were allocated using a combination of a design day and commodity allocator similar to the method employed by the FERC. As I mentioned earlier, I ran an alternative case using a simple commodity allocator.

Q. How were the remaining Operation and Maintenance Expenses allocated?

A. Distribution O&M expenses follow the allocation of distribution plant. Customer Accounts, Sales Expenses, and Administrative and General Expenses were allocated using a variety of methods based on direct assignments, revenues, sales, gas costs, number of bills and number of customers. Whenever possible, specific information detailing class cost responsibilities was utilized to develop the most accurate cost study possible. Externally developed allocators were developed for Accounts 902, 903 and 904. For example, Account 902, Meter Reading Expense, was allocated to customer classes on an externally developed allocator (CUST902), which weighted the number of meters with the average time to read the meters. Uncollectible accounts expense in Account 904 is allocated to classes in proportion to the write-offs experienced in the test year. Administrative and General ("A&G") expenses are allocated partly on the labor allocator, partly on revenue requirements, and partly on plant in service. Each of these allocators was developed internally.

For all other accounts, some form of labor, customer or plant allocator was chosen to best represent the nature of the costs in the expense category to be allocated. The work papers contain a complete detail of the development of each allocator utilized in the cost of service study.

Q. What are the remaining operating expenses?

A. The remaining operating expenses consist of depreciation and amortization expenses, taxes other than income taxes, amortization of investment tax credit, state franchise taxes and federal income taxes.

Q. How were they allocated?

A. Depreciation expenses were allocated on the basis of plant in service similar to the allocation of depreciation reserves. Taxes Other Than Income Taxes that are plant related were allocated on PLANT and those that are labor related were allocated on the LABOR allocator discussed earlier. Federal income taxes and state franchise taxes were computed for each customer class based on the allocated expenses previously discussed.

Accounting Class Cost Study Results

Q. Could you summarize the results of your cost study at present rates?

A. The results of my study demonstrate that the rates presently in effect generate different rates of return for each class. As Schedule G-1 clearly demonstrates, the Company's current rates produce inequities among rate class. The residential class generates lower rates of return. In fact, the returns are negative, suggesting that current rates do not even cover the Company's expenses, let alone compensate for the investment necessary to serve them. On the other hand, the irrigation rate class, with the majority of its consumption occurring in the summer, generates large positive returns, in excess of the return requested by the Company.

Unbundled Costs to Serve

Q. How does your accounting cost of service study relate to the development of unbundled cost to serve the gas supply and transportation functions?

A. MAC's Cost of Service Model addresses cost to serve as a three dimensional array. So far, we have discussed only two dimensions, the accounting cost dimension, showing the details of the rate base and expense items that determine total cost to serve and the second dimension, the class dimension, showing how each of these costs is allocated to customer classes. This discussion relates to the more traditional cost of service studies well recognized by the Commission. In order to support unbundling efforts, MAC's Cost of Service Model identifies costs by functions such as production or commodity. Allocations to the class and function dimensions are performed automatically and simultaneously. For example, the allocation of metering investment was determined to be related to the distribution function alone and not to the gas supply function. The meter allocator was defined as 100% distribution customer-related and at the same time these costs were allocated to individual customer classes. While many of the allocators used in the cost study were assigned directly to one function or another, other allocators were developed internally in the cost study and resulted in allocations to more than one functional cost category. For example, some cost items were allocated to the plant in service. Recall that plant consists of investments in production facilities, which are primarily gas supply-related, as well as transportation-related investment items such as mains, services and meters. As a result, items allocated on plant displayed both a gas supply and transportation component to their cost to serve.

Q. Have you prepared any unbundling cost of service studies as part of your efforts to analyze the Company's overall costs?

A. Yes, I have. Following the standard cost allocation procedures outlined earlier in my testimony, I have aggregated costs and prepared unbundled cost of service results for the following principal areas of cost recovery:

Production Demand Component
Transmission Demand Component
Distribution Mains Component
Distribution Regulators Component
Distribution Other Component
Commodity Gas Cost Component
Commodity Other Component
Customer Services Component
Customer Meters Component
Customers Regulator Component
Customer Deposits Component
Customer Advances Component
Customer Contributions Component
Customer Forfeited Discounts Component
Customer Miscellaneous Service Revenue Component

Customer Meter Reading Component

Customer Billing Component

Customer Sales Component

These results are summarized in Schedules G-5 and G-6. This Exhibit shows the allocation of each item contributing to revenue requirements into the eighteen functions, listed above and further summarizes them into capacity, commodity or customer costs and supply or delivery costs.

Q. How do you determine the gas supply and transportation-related costs from the unbundled cost of service study results you have presented?

A. Very simply, the transportation component of cost to serve consists of the transmission, distribution and customer costs shown on Schedules G-5 and G-6. The remaining costs are gas supply related. I have added subtotals for the supply and delivery function to simplify understanding.

RATE DESIGN

Q. Was there a logical progression in your efforts to perform the rate design?

A. Yes. My rate design efforts were performed in four discrete steps. First, I determined which rates were to be offered in the future and merged discontinued rates into their otherwise applicable rates. Next, I compared the base rate revenues generated by each customer rate class with the costs to provide service as shown in the accounting cost of service study. Next, I established rate caps limiting the increases and allocated subsidies to eventually determine appropriate class revenue targets for the rate design. Before actually designing rates, I established the level of gas costs to be embedded in base rates. Finally, I performed the rate design itself utilizing the class revenue targets, the cost study's component cost information and class-by-class bill impact analyses in order to interactively develop a practical and reasonable rate design recommendation.

Rate Reclassification

Q. Are you recommending any changes to the definition of rate classes?

A. Yes, I have proposed some minimal changes, primarily consolidation to streamline rate administration. At present the Company's tariffs include seven air conditioning rates. Since their inception, only nine customers have enrolled on these rates. In the test year only three exhibited usage patterns indicating air conditioning use and two of those were Citizens' offices. The level of participation on these rates is insufficient to justify their continuation. Therefore I propose to eliminate the seven air conditioning tariffs

Gas Costs in Base Rates

Q. Please describe your derivation of gas costs for rate design purposes.

A. Recall that the pro forma revenue requirements include Mr. Cogan's forecast of test year gas costs using forecasted commodity prices. On average, gas costs were nearly 44 cents per therm. The cost study allocated these gas costs to customer classes. By utilizing this data, I was able to identify the total gas costs for inclusion either in base rates or to be recovered through the PGA.

Q. What amount of gas costs have you embedded in the design of base rates?

A. I established the average gas costs in base rates at forty cents per therm.

Q. Why did you choose this amount?

A. In general, the level of gas costs to be included in base rates should be equal or slightly less that the average costs of gas. This practice allows the PGA factor to be a small positive figure. Large PGA factors or negative factors tend to confuse price signals and should be avoided, if possible. Based on Mr. Cogan's gas forecast analysis, this level represents slightly less than the average gas costs expected in the first year rates are to be in effect.

Q. Recognizing that the PGA clause will automatically adjust rates for future variations in gas costs, would a smaller figure be equally acceptable?

A. The purpose of embedding gas costs in base rates is to provide a price signal indicating the likely costs to serve. In the past, the PGA has been a sizable addition to customer base rates. This makes it more difficult for customers to understand and predict future gas bills. If the base rates include the expected average cost of gas, then there is some expectation that the unbiased estimate of the PGA rate will be near zero.

Q. Using the forty-cent figure in base rates, is the Company's expectation that PGA rates will be close to zero next year?

A. Gas prices have been volatile and probably will continue to be so. Even if Mr. Cogan's current forecast is accurate, the PGA rate will most likely swing positive, all else being equal. The increase is due to potential increased pipeline reservation charges stemming from the FERC's El Paso ruling.

Class Revenue Targets

Q. Let's turn now to the subject of revenue targets. Could you explain this term?

A. In the accounting cost of service studies, I identified the costs to serve each customer class at a uniform rate of return. However, it is frequently impractical to design rates to exactly match calculated costs. In some instances, doing so would result in unacceptably large increases to some classes and substantial decreases to others. Rate stability and bill impact considerations dictate gradualism in rate design initiatives to moderate change and avoid such problems. Typically, the rate design process includes a rate cap limiting the percentage increase assigned to any customer class.

Q. How did you establish class revenue targets for your rate design?

A. The calculation of the proposed revenue targets is shown on Exhibit JLH-6. The revenue targets are computed in a multi-step process. On page 1 of Exhibit JLH-6, I removed all gas costs and gas revenues and identified the present margins by rate class and the cost to serve each class, based on the accounting cost of service study at uniform rates of return. Next, on page 2,I identified the percentage increase that would be required to eliminate all inter-class subsidies. Then, I placed an upper cap or limit to the allowable increase to 125% of the average increase requested by the Company. I also set a floor price of 0% to ensure that no class received a base rate decrease. The deficiency resulting from my caps were allocated to uncapped classes based on the difference between present revenues and revenues producing uniform rates of return. Next, I added the gas costs as allocated to each customer rate class in my Class Cost of Service Study. Then I subtracted the gas cost revenues to be recovered through the operation of the PGA. I assumed that all customer classes would be expected to pay all of their gas costs, even the low-income discounted rates. I then computed the impact of lowering rates to the low-income classes. The low-income subsidy was assigned to all rate classes on the basis of their sales volumes. The resulting totals formed the starting point for rate design efforts.

Rate Design By Class

Q. Please describe your rate design.

A. I have proposed a very straightforward rate design for the Company because the Company is unbundling rates and also proposing a rate reclassification. The Company's present rates are flat or have one head block and tail block price. I concluded that rate administration and customer understanding would be promoted by maintaining the existing rate structures.

Q. Please describe your rate design calculations.

A. As an example, I have provided a detailed calculation for the residential class on Exhibit JLH-6, page 12. I began with the billing units and the revenue target, previously developed. Next, I removed the gas costs to be embedded in base rates. This was the gas cost allocated in the cost study less the gas costs to be recovered in the PGA. The remaining revenues must be generated from the customer charge and the base rate. Initially, I raised the customer charge by 110% of the increase to the class's revenue requirements, subject to the constraint that the customer charge did not exceed the customer cost. For this calculation I grouped all of the residential classes. Next, I rounded the customer charge, relying on a weighted average of the similar classes, i.e., one customer charge for all residential rates. Finally, I calculated the therm charge in order to achieve the revenue target for the class and rounded it. My rate design calculations are summarized on Schedule H-3.

Q. Have you proposed any revisions to the Company's low-income rates?

A. Yes, the Company is proposing an expansion of its CARES program. As a result on the ACC's previous rulings, low income program funding was approximately $120,000 in the test year. Actual program expenditures were slightly less. The CARES program will be expanded to include the SCGD. Customers currently enrolled and receiving CARES benefits through the Company's electric utility will be automatically enrolled in the gas utility's program. As a result of the lower average income levels in the SCGD, nearly 1,400 additional customers are expected to receive CARES benefits.

The proposed expansion is targeted to increase customer awareness, raise participation levels among eligible customers, expand weatherization and insulation programs, and increase the magnitudes of the discounts provided. Annual program costs are estimated at $220,000. Based on test year sales of 131 million therms, this equates to a surcharge of $0.00166 per therm, almost twice the present rate of $0.00098.

As shown on page 13 of Exhibit JLH-6, the CARES discounts are anticipated to total approximately $150,000 per year. Monthly discounts are provided for up to 100 therms of usage in the winter months. The proposed rate design incorporates four basic changes. First, the CARES discounts will be expanded from five to six months by including the month of April in addition to the existing period of November to March. Second, the CARES discount will be increased from 15% to approximately 20% of base rates, the same level as the present Medical CARES program. Third, since the regular and Medical CARES discounts are the same, they have been combined into a single CARES rate to simplify rate administration. Finally, the rate is stated as a discount of 15 cents per therm, rather than a percentage discount.

Q. How did you design the cogeneration rate?

A. The Company does not presently have any customers on the cogeneration rate, so I designed the rate on a theoretical basis. I started with the Large Volume Industrial rate's margin and then added the gas costs for a 100% load factor rate.

Q. Please describe the proposed T-2 Transportation rate?

A. This rate is to be offered to transportation customers served by dedicated transmission mains. No customers qualified for this service during the test year, but one will qualify in the future, assuming the ACC approves. Citizens are requesting that a transmission line currently owned by its Santa Cruz Electric Division be transferred to the Gas Division. The line provides natural gas service to the Valencia generating station. However, the plant is dual fueled and frequently burns oil rather than natural gas. In order to assure proper pricing and revenue recovery, the rate's reservation charge is based on equal monthly installments to recover the costs to provide service, rather than billed on the basis of metered quantities.

Bill Impacts

Q. Have you assessed the impact of your rate design on existing customers?

A. Yes, I have prepared a set of bill comparisons for each rate in both the NAGD and SCGD, shown as Schedule H-4.

Revenue Proof

Q. Please describe your proof of revenues?

A. Schedule H-3 computes the present and proposed sales revenues for each of the various rate schedules. The first six pages detail present rates using unadjusted billing units, and the next six pages detail present rates using normalized and year-end customer annualized billing units. The final six pages of Schedule H-3 detail proposed rates. This exhibit identifies each rate schedule and provides identifying criteria, customer charges, volumetric charges, and applicable surcharges for the PGA Adjustment. Proof of revenues is provided by calculating the revenue recovery for each class by applying both present and proposed rates to the unadjusted and adjusted billing units.

Schedule H-1 provides a summary of base revenue, PGA revenue, and total revenue by class of service. The actual dollar and percent impact by class of service is provided on this schedule. At the bottom of this sheet, I have indicated the total revenues projected under new rates, as well as present rates. More importantly, the total proposed revenues derived from rates can be compared with proposed revenue requirements identified in Mr. Mason's testimony. The minor difference is attributable to rounding.

OTHER TARIFF CHANGES

Main and Service Extension Policies

Q. Why are you proposing to change the Company's current rules regarding main and service extensions?

A. I am proposing two minor changes to the policy. Mr. Smith advised me that the current policy does not recognize nor encourage new customers to provide trenching and back-filling services. I have proposed that a $3.00 per foot credit be recognized for customers providing their own service trench. By explicitly recognizing these potential cost savings, Citizens can encourage more efficient development and reduce its future investments at the same time. The second change is also minor. The current policy requires that Citizens collect customer advances as small as $50. I have increased the minimum to $100. The administrative costs to book and track such small advances may well be uneconomic.

Budget Billing Plan

Q. What changes have you proposed to the budget billing plan?

A. I have made a number of minor changes to our rules and regulations to more clearly document our program and to eliminate ambiguity that could lead to customer confusion.

Miscellaneous Service Fees

Q. Have you proposed changes to the miscellaneous service fee tariffs currently shown on original sheet #32?

A. Yes. I have proposed to increase the present tariff rates to make them more compensatory.

Q. What is the purpose of the miscellaneous service fee tariffs?

A. These tariffs are intended to provide prices for a number of incidental services provided by the Company at the request of the customer, or to bill the customer for avoidable costs generated by his action or inaction. In general, the present rates are extremely low and non-compensatory.

Q. On what basis do you make this judgment?

A. With the assistance of Company marketing and central office personnel, I have performed a simplified cost of service study for each of the services currently provided. This study is shown as Exhibit JLH-7. For each service I have described the service and indicated the costs incurred in providing it. In each instance, the Company's costs to provide the service are greater than the current charges.

Q. How did you establish the rates you are proposing?

A. As with all rate design, there was some subjectivity in my rate making. In addition to the cost study I performed, I had a tabulation of similar charges from other utilities prepared. This information is shown as Exhibit JLH-8. I recognize that it would be unrealistic to attempt to set the miscellaneous fees at their full costs to serve. However, I believe that Citizen's rates tend to be lower than many other utilities and can be raised to comparable levels without undue hardship to customers.

Q. In many instances, you have proposed a substantial increase to the fees. How did you compute the expected increase in revenues to be derived?

A. Initially, I approached this problem from a theoretical perspective. Economic theory suggests that customers will exhibit some response to a price change. If prices increase dramatically, than the quantity demanded should be reduced. Unfortunately, I could not locate any determinative studies on which to base these calculations. Consequently, I assumed that the higher prices would not prove a deterrent and billing units would be unchanged. The results of this calculation are shown on schedule JLH-9. This analysis shows the miscellaneous tariff fee revenues generated under present rates and those expected under the rates that I have proposed. The increase in miscellaneous tariff fee revenues is treated as an offset to total company revenue requirements and therefore was used to reduce target revenues required from sales rates.

Other Tariff Changes

Q. Please describe the additional tariff language changes that you are proposing.

A. I have proposed a number of minor language changes to the tariffs to simplify rate administration, remove superfluous information and clarify ambiguous tariff language. To simply the review of these changes, I have provided a redlined version of the tariffs thereby highlighting all proposed changes, labeled as Exhibit JLH-10. This exhibit also includes and highlights the revisions to the T-1 transportation tariff's terms and conditions proposed by Mr. Cogan and discussed at length in his testimony.

Q. Are these statements and exhibits set forth in your direct testimony true and correct to the best of your knowledge?

A. Yes, they are.

Q. Does this conclude your testimony?

A. Yes, it does.

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QUALIFICATIONS OF JAMES L. HARRISON

Q. Would you describe your educational background?

A. My undergraduate work was taken at Lehigh University, Bethlehem, Pennsylvania. I graduated in 1968 with a Bachelor of Science degree in Engineering Mechanics, with a strong background in Electrical Engineering. Following graduation, I joined General Electric Company in Pittsfield, Massachusetts, and enrolled in their evening program, taking courses in Engineering Economics. While still employed at GE in a field service position, I enrolled in a graduate program in Electrical Engineering at Old Dominion University, Norfolk, Virginia. I also took accounting courses at the City College of Charleston (South Carolina) and at the Southeastern Branch of the University of Connecticut, located in New London, Connecticut. I then left General Electric to pursue full-time graduate studies at the University of Connecticut. I graduated in 1973 with a Masters of Business Administration degree, specializing in Industrial Administration. I joined Gilbert Associates, Inc., a large engineering and consulting firm serving the utility industry, and completed numerous short courses offered by the Company in the fields of Management Science, Construction Management and Computer Science. I have also attended numerous industry workshops and seminars in the areas of cost of service and rate design for the electric utility industry.

Q. Are you a registered engineer?

A. Yes, since 1975, I have been a licensed professional engineer by examination in the State of Pennsylvania, License No. PE-023191-E.

Q. Please describe your professional background.

A. I have been employed by Management Applications Consulting, providing management consulting services to utilities since 1984. Previously, I was employed by Gilbert Associates, Inc., in various capacities for over 11 years. Prior to that, I was employed by General Electric Company Ordinance Systems Division for over three years.

Q. Beginning with your first employment, would you briefly describe your duties with General Electric?

A. Upon graduation from Lehigh University, I was employed by General Electric Company to work in a field service capacity on the Poseidon missile fire control system. After an intensive training program, I was assigned to the Training Facilities Division and given responsibilities for construction management, installation supervision and certification testing of Poseidon Missile Fire Control Training Systems at naval training stations at Dam Neck, Virginia; Charleston, South Carolina and New London, Connecticut. My assignments included the development and letting of contracts for suitable subcontractors, critical path method scheduling, cost accounting and actual equipment certification testing. During this period, I received first-hand knowledge of costs and cost control in large organizations.

Q. Please describe your duties with Gilbert Associates, Inc.

A. My initial assignment was with the Scheduling Department, in charge of the development of engineering and construction Exhibits for large electric utility projects. Most of my Exhibits employed the precedence method of Critical Path Method ("CPM"), scheduling to computer model the interfaces between engineering disciplines, construction subcontractors and equipment suppliers. I developed sophisticated engineering Exhibits for two nuclear plants and construction Exhibits for two fossil plants. I also attached the engineering and construction activities for major additions and modifications to Rochester Gas and Electric's R. E. Ginna Nuclear Power Plant. My next assignment was as an administrator for a group of approximately 150 engineers. My responsibilities included budgeting, forecasting, staffing and supervision of computer program development activities. I also acted as special consultant on matters of statistics and probabilistic inference. In 1978, I transferred to the Management and Consulting Division and have held progressively more responsible positions with its Cost and Load Analysis Department, culminating with the title of Department Manager and Senior Consulting Engineer. In this position, I was responsible for the administration of a group of professionals working in the field of Regulatory Services. My work required technical supervision over my colleagues in the performance of cost of service studies and various rate and cost-related studies.

Q. Please describe your duties with Management Applications Consulting, Inc.

A. As a principal in the firm, I am responsible for all phases of consulting services offered to electric and gas utilities. Acting as project manager and principal consultant, I provide services in all phases of utility rate and regulatory matters.

Q. Could you please expand on your technical experience in cost and load analysis for utilities?

A. My work has centered in four areas: the performance of accounting cost of service and rate design studies, the performance of marginal cost of service studies, the development of new and improved methods of performing either type of cost of service study and, lastly, special projects. Let me discuss these activities one at a time.

I have performed numerous accounting cost of service and rate design studies, including conventional, time-differentiated bundled and fully unbundled studies. In the process of conducting such studies, I have supervised the development of computerized loss analyses and load research based class demand analyses. Working with the results of these studies, I have performed conventional rate designs as well as developed unbundled, time of day, load management, conservation, interruptible, curtailable and experimental rate designs.

In the area of methods and procedures, I was responsible for developing the methods utilized by 50 professionals in performing time-differentiated accounting cost studies. In 1977, I devised the Probability of Dispatch ("POD") method to allocate production costs to time periods and have supervised the development of computer software to carry out the method. In 1995, I devised the Market Based Allocation ("MBA") to assign gas costs to customer classes. In a similar vein, I have been the system architect to lay out the development of a system of interrelated computer programs to vertically integrate plant allocations to time periods and customer classes.

My responsibilities under the category of special assignments are many and varied. I have been an active member of the IEEE Demand Side Management Committee and the Association of Energy Service Professionals. I have authored generic cost of service and rate design testimony for hearings held by the Public Utility Commission of Texas, the Rhode Island Public Utilities Commission and the Florida Public Service Commission. I assembled a primer on marginal costing techniques for a Central American utility. I have reviewed the marginal costing techniques employed by a French consulting firm for a utility whose generation is predominantly hydro-electric. I have been a principal investigator in several Electric Power Research Institute sponsored research projects. I have negotiated transmission wheeling contracts, performed economic feasibility studies, participated in large-scale management audits, developed short and long term econometric forecasting models, prepared gas utility supply plans and prepared portions of Engineer's Reports for municipal bond financing.

Q. Have the results of your work been filed with any regulatory commission?

A. Yes, in the course of my employment, the studies in which I have participated have been presented before the Federal Energy Regulatory Commission, the Arizona Corporation Commission, the Massachusetts Department of Telecommunications and Energy, the Public Utility Commission of Texas, the Pennsylvania Public Utility Commission, the Public Service Commission of Wisconsin, the Public Service Commission of Ohio, the New Hampshire Public Utilities Commission, the Maine Public Utilities Commission, the New Jersey Board of Public Utilities, the New York

Public Service Commission, the Public Service Commission of Florida, Illinois Commerce Commission, Rhode Island Public Utilities Commission and the Vermont Public Service Board.

Q. Could you briefly explain your experience with gas utilities?

A. Starting over twenty years ago, I was heavily involved in the Massachusetts' generic investigation into the feasibility of implementing marginal cost-based rates, Docket No. 18810. I performed electric utility marginal cost studies for New Bedford Gas & Edison Light Company and Fitchburg Gas & Electric.

In the 1990's, I developed time differentiated gas cost allocators, utilizing my "Market Based Allocation" technique for Bay State Gas Company, Northern Utilities, EnergyNorth Natural Gas, Fitchburg Gas and Electric and Fall River Gas Company. I assisted in load research sample design for Boston Gas as part of a major demand side management program. I presented technical conferences to the staffs in Massachusetts, New Hampshire, Maine, and New York on the proper cost techniques to unbundle gas distribution utility rates.

I have evolved a marginal gas cost of service study procedure which was employed in filings for Berkshire Gas Company, Boston Gas Company, Bay State Gas Company, Fall River Gas Company, Northern Utilities, EnergyNorth Natural Gas, Fitchburg Gas and Electric Company and Commonwealth Gas Company. I assisted the Vermont Gas Company in measuring costs and benefits of various supply side projects. I developed a computerized ogive curve employed by Boston Gas as part of its weather normalization calculations and assisted in the initial development of an end use load research experiment to monitor the effectiveness of conservation and load management programs. I proposed and implemented commercial and industrial reclassification for a half dozen New England gas utilities. I have participated in all phases of Demand Side Management programs but most heavily in the computation of avoided cost studies. I have also participated in the preparation of Integrated Resource Plans for gas utilities, concentrating on the areas of load forecasting, supply planning, and profitability analyses. I have developed the Market Based Allocation Method for production cost allocation for local distribution utilities and employed it successfully in unbundling accounting cost of service studies for utilities in four states.

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Citizens Communication Company
Sales and Demand Model
Input Data for weather Normalization

NAGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	FY2001
Number of Customers (Bills)														
1 10-Residential	96,059	97,014	97,592	98,333	98,417	99,005	98,380	99,896	99,117	99,762	100,030	100,938	101,510	1,184,543
2 11-Residential A/C	6	6	6	6	6	6	6	6	6	6	5	5	5	70
3 12-CARES	1,285	1,582	1,563	1,635	1,610	1,601	1,583	1,602	1,564	1,645	1,455	1,550	1,719	18,675
4 13-CARES Med Life Support	1	1	1	1	1	1	1	1	1	1	1	1	1	12
5 20-Sm Vol Commercial	9,197	9,317	9,318	9,436	9,343	9,325	9,227	9,272	9,182	9,291	9,352	9,518	9,619	111,778
6 21-Sm Vol Commercial A/C	4	4	4	4	4	4	4	4	4	4	4	4	4	48
7 22-Lg Vol Commercial	14	13	13	13	13	13	13	13	13	13	12	12	12	155
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	9	9	9	9	9	9	9	9	9	9	9	9	9	108
10 30-Sm Vol Industrial	16	19	16	19	14	15	18	15	20	16	17	16	15	201
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	6	6	6	6	6	6	6	6	6	6	6	6	6	72
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	11	11	11	11	11	11	10	10	10	10	10	10	10	126
15 40-Sm Vol Pub Auth	828	830	823	851	830	841	838	848	852	872	859	880	874	10,152
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	4	5	5	5	5	5	5	5	5	5	5	5	5	59
18 T1-Lg Vol Pub Auth Transp	6	6	6	6	6	6	6	6	6	6	6	6	6	72
19 44-Gas Light Service	4	4	4	4	4	4	4	4	4	4	4	4	3	48
20 60-Irrigation Service	8	8	9	7	7	10	7	7	7	7	7	7	7	91
21 TY TOTAL	107,458	108,835	109,386	110,346	110,286	110,862	110,117	111,704	110,806	111,657	111,782	112,971	113,805	1,326,210
22 Total Sales	107,432	108,809	109,360	110,320	110,260	110,836	110,092	111,679	110,781	111,632	111,757	112,946	113,780	1,325,904
23 Total Transportation	26	26	26	26	26	26	25	25	25	25	25	25	25	306

SCGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	FY2001
Number of Customers (Bills)														
1 10-Residential	4,989	4,972	4,986	5,032	5,065	4,981	5,025	4,992	4,996	5,103	5,177	5,082	5,093	60,399
2 11-Residential A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 12-CARES	1,370	1,370	1,370	1,370	1,370	1,370	1,370	1,370	1,370	1,370	1,370	1,370	1,370	16,441
4 13-CARES Med Life Support	1	1	1	1	1	1	1	1	1	1	1	1	1	12
5 20-Sm Vol Commercial	586	586	575	538	570	548	549	554	546	551	562	544	575	6,709
6 21-Sm Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 22-Lg Vol Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 30-Sm Vol Industrial	3	3	3	3	3	3	1	1	1	3	2	3	3	29
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 40-Sm Vol Pub Auth	68	67	77	64	70	69	73	76	74	82	80	66	67	866
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19 44-Gas Light Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20 60-Irrigation Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21 TY TOTAL	7,017	6,999	7,012	7,008	7,079	6,972	7,019	6,994	6,988	7,110	7,192	7,066	7,109	84,456
22 Total Sales	7,017	6,999	7,012	7,008	7,079	6,972	7,019	6,994	6,988	7,110	7,192	7,066	7,109	84,456
23 Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Citizens Communication Company
Sales and Demand Model
Input Data for weather Normalization

NAGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	FY2001
Sales Volumes, Therms														
1 10-Residential	10,131,903	10,956,521	10,080,842	6,413,180	3,939,921	2,029,971	1,554,326	1,456,764	1,536,582	1,901,262	3,372,582	8,212,379	11,805,746	61,586,233
2 11-Residential A/C	830	817	734	448	294	158	228	254	182	178	116	445	634	4,684
3 12-CARES	108,779	151,279	137,099	88,964	52,295	27,876	22,258	20,230	21,568	28,667	44,088	114,193	173,986	817,296
4 13-CARES Med Life Support	142	144	131	65	36	16	14	13	13	15	46	112	151	747
5 20-Sm Vol Commercial	3,666,227	3,982,095	3,646,595	2,580,616	1,734,819	1,344,806	1,181,781	1,110,858	1,146,814	1,276,992	1,670,933	3,123,594	4,099,377	26,466,130
6 21-Sm Vol Commercial A/C	2,560	2,635	2,320	1,649	1,509	2,596	2,763	2,618	2,289	1,844	1,962	2,071	2,776	26,816
7 22-Lg Vol Commercial	361,942	282,772	251,914	200,917	141,175	104,761	79,474	71,920	80,787	102,889	134,203	241,581	283,936	2,054,335
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	266,344	222,954	217,832	201,068	152,931	139,457	134,174	132,869	126,916	162,289	195,698	261,442	266,344	2,213,974
10 30-Sm Vol Industrial	71,608	119,867	109,025	128,771	59,928	56,895	67,659	43,874	77,000	53,889	59,771	94,662	98,204	942,949
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	322,074	289,324	254,648	264,536	231,027	225,494	206,936	143,935	163,789	190,611	239,465	274,068	466,142	2,805,907
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	1,363,084	1,117,094	1,103,212	1,356,987	1,356,688	1,111,210	1,147,399	1,355,385	1,579,366	1,031,195	1,033,303	1,355,023	1,363,084	14,909,946
15 40-Sm Vol Pub Auth	858,094	938,132	862,894	514,654	277,475	146,529	131,925	94,366	82,820	125,266	258,728	727,953	982,482	5,018,836
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	121,809	196,803	121,671	134,382	70,331	34,524	24,026	23,482	26,642	36,324	65,364	133,816	192,463	989,174
18 T1-Lg Vol Pub Auth Transp	681,947	561,835	557,385	523,549	338,822	275,602	260,216	249,647	273,288	388,753	532,644	668,876	681,947	5,312,564
19 44-Gas Light Service	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,844	8,690	8,646	106,194
20 60-Irrigation Service	2,344	2,860	1,348	2,085	8,476	42,642	37,102	38,602	25,159	22,361	16,077	6,679	1,818	205,735
21 TY TOTAL	17,968,553	18,833,998	17,356,516	12,420,737	8,374,593	5,551,403	4,859,147	4,753,683	5,152,081	5,331,401	7,633,824	15,225,584	20,427,736	123,461,520
22 Total Sales	15,657,178	16,932,115	15,478,087	10,339,133	6,526,152	4,025,134	3,317,358	3,015,782	3,172,511	3,749,164	5,872,179	12,940,243	18,116,361	101,025,036
23 Total Transportation	2,311,375	1,901,883	1,878,429	2,081,604	1,848,441	1,526,269	1,541,789	1,737,901	1,979,570	1,582,237	1,761,645	2,285,341	2,311,375	22,436,484

SCGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	FY2001
Sales Volumes, Therms														
1 10-Residential	501,115	573,117	426,960	261,603	212,265	75,428	86,835	80,889	86,849	89,720	122,384	337,851	565,394	2,855,017
2 11-Residential A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 12-CARES	119,284	130,999	97,542	59,196	35,641	21,293	20,060	19,369	21,051	22,286	29,177	80,521	119,284	656,419
4 13-CARES Med Life Support	87	96	71	43	26	16	15	14	16	16	47	82	87	529
5 20-Sm Vol Commercial	192,161	248,594	154,719	120,233	83,306	56,661	51,034	53,250	54,666	61,791	81,644	140,372	198,286	1,298,428
6 21-Sm Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 22-Lg Vol Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 30-Sm Vol Industrial	16,640	13,621	13,621	3,253	10,885	11,302	33	30	9	5,417	304	11,026	17,171	86,141
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 40-Sm Vol Pub Auth	77,205	101,312	71,797	34,521	19,621	13,344	5,375	6,112	8,217	6,348	17,106	36,197	79,666	397,156
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19 44-Gas Light Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20 60-Irrigation Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21 TY TOTAL	906,493	1,067,739	764,710	478,848	361,744	178,044	163,353	159,664	170,808	185,577	250,663	606,048	979,887	5,293,691
22 Total Sales	906,493	1,067,739	764,710	478,848	361,744	178,044	163,353	159,664	170,808	185,577	250,663	606,048	979,887	5,293,691
23 Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Citizens Communication Company
Sales and Demand Model
Input Data for weather Normalization

NAGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	FY2001
Present Base Revenue (Excl PGA)														
1 10-Residential	4,937,266	5,211,832	4,921,411	3,309,462	2,222,195	1,375,261	1,161,741	1,136,363	1,171,444	1,291,589	1,984,802	4,125,567	5,702,449	32,848,932
2 11-Residential A/C	395	391	354	226	159	97	120	130	103	96	76	221	305	2,368
3 12-CARES	54,287	73,700	68,248	47,276	31,026	20,219	17,612	16,872	17,322	20,319	26,741	57,925	85,396	451,548
4 13-CARES Med Life Support	68	69	63	34	21	12	11	11	11	12	25	54	72	390
5 20-Sm Vol Commercial	1,471,628	1,574,939	1,463,689	1,052,224	731,444	576,811	519,482	492,198	505,707	535,593	708,069	1,268,541	1,636,006	10,900,325
6 21-Sm Vol Commercial A/C	1,013	1,041	920	663	609	922	976	929	817	666	783	825	1,095	10,164
7 22-Lg Vol Commercial	123,003	97,118	86,626	69,287	48,975	36,594	27,996	25,428	28,443	35,957	46,529	83,038	97,438	708,993
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	25,697	21,792	21,331	19,822	15,490	14,277	13,802	13,684	13,148	16,332	19,339	25,256	25,697	219,968
10 30-Sm Vol Industrial	21,438	41,610	33,441	43,107	20,995	19,896	20,700	15,490	26,330	18,942	21,016	33,011	34,206	315,977
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	99,552	89,475	78,805	81,848	71,537	69,835	64,124	44,739	50,848	59,101	74,133	84,781	115,584	868,778
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	64,465	54,300	58,975	61,987	59,637	53,214	55,131	61,907	65,064	53,381	53,413	60,716	64,465	702,190
15 40-Sm Vol Pub Auth	327,766	354,671	328,320	197,612	109,942	61,083	53,353	41,708	37,473	52,113	104,078	275,737	356,914	1,943,855
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	39,484	63,773	39,515	38,094	22,822	11,455	8,095	7,941	8,962	11,187	21,442	43,504	62,406	316,273
18 T1-Lg Vol Pub Auth Transp	48,689	40,080	39,404	36,668	23,340	18,290	17,473	17,073	18,445	27,152	37,355	47,448	48,689	371,417
19 44-Gas Light Service	3,960	3,960	3,960	3,960	3,960	3,960	3,960	3,960	3,960	3,960	3,960	3,901	914	47,456
20 60-Irrigation Service	609	929	472	695	2,629	13,154	11,484	11,946	7,804	5,387	6,163	2,591	744	63,861
21 TY TOTAL	7,219,318	7,629,679	7,145,533	4,962,963	3,364,780	2,275,078	1,976,058	1,890,378	1,955,880	2,131,787	3,107,924	6,113,116	8,232,380	49,772,495
22 Total Sales	7,080,468	7,513,508	7,025,824	4,844,487	3,266,313	2,189,296	1,889,653	1,797,714	1,859,224	2,034,921	2,997,817	5,979,696	8,093,529	48,478,920
23 Total Transportation	138,851	116,171	119,710	118,476	98,467	85,782	86,405	92,664	96,657	96,866	110,107	133,420	138,851	1,293,575

SCGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	FY2001
Present Base Revenue (Excl PGA)														
1 10-Residential	349,656	360,394	280,308	184,984	161,171	89,193	79,590	78,159	81,611	80,806	98,471	230,430	391,895	2,074,771
2 11-Residential A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 12-CARES	78,311	84,796	66,248	44,323	29,590	21,207	20,445	19,950	21,050	21,855	26,275	56,708	40,929	490,758
4 13-CARES Med Life Support	59	64	50	33	23	16	16	15	16	16	36	56	32	399
5 20-Sm Vol Commercial	105,144	135,152	85,510	67,424	47,672	32,878	29,616	30,666	31,409	35,099	45,893	77,607	100,968	724,070
6 21-Sm Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 22-Lg Vol Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 30-Sm Vol Industrial	8,396	6,885	6,885	1,691	5,498	5,705	26	25	11	2,764	183	5,587	7,610	43,656
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 40-Sm Vol Pub Auth	39,887	52,273	37,241	18,531	10,811	7,388	3,299	3,680	4,757	3,813	9,389	19,253	36,800	210,323
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19 44-Gas Light Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20 60-Irrigation Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21 TY TOTAL	581,453	639,563	476,240	316,987	254,765	156,387	132,991	132,495	138,854	144,354	180,246	389,641	578,234	3,543,977
22 Total Sales	581,453	639,563	476,240	316,987	254,765	156,387	132,991	132,495	138,854	144,354	180,246	389,641	578,234	3,543,977
23 Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Citizens Communication Company
Sales and Demand Model
Input Data for weather Normalization

NAGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	FY2001
PGA Revenue														
1 10-Residential	1,082,612	1,237,652	1,183,015	837,088	552,304	296,929	233,637	219,552	231,603	652,634	1,158,014	2,820,475	4,054,797	10,505,516
2 11-Residential A/C	89	92	86	58	41	23	34	38	27	61	40	153	218	744
3 12-CARES	11,622	17,087	16,088	11,611	7,329	4,076	3,344	3,048	3,250	9,839	15,137	39,218	59,756	141,649
4 13-CARES Med Life Support	15	16	15	8	5	2	2	2	2	5	16	38	52	128
5 20-Sm Vol Commercial	391,886	449,936	428,066	336,985	243,357	196,978	177,947	167,712	173,141	438,615	573,928	1,072,911	1,408,092	4,651,462
6 21-Sm Vol Commercial A/C	274	298	272	215	212	380	416	395	346	633	674	711	954	4,827
7 22-Lg Vol Commercial	38,692	31,953	29,575	26,240	19,807	15,347	11,969	10,860	12,199	35,342	46,099	82,983	97,532	361,065
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 30-Sm Vol Industrial	7,655	13,545	12,799	16,817	8,408	8,335	10,189	6,625	11,627	18,511	20,531	32,516	33,733	167,559
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	34,430	32,694	29,896	34,548	32,413	33,035	31,165	21,734	24,732	65,475	82,256	94,142	160,120	516,520
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 40-Sm Vol Pub Auth	91,726	106,005	101,300	67,210	38,926	21,463	19,865	14,247	12,503	43,026	88,869	250,048	337,479	855,188
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	13,021	22,239	14,284	13,597	9,867	5,058	3,618	3,546	4,023	12,477	22,453	45,966	66,111	170,149
18 T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19 44-Gas Light Service	948	1,002	1,041	1,158	1,244	1,299	1,335	1,339	1,339	3,045	3,038	3,002	2,970	19,790
20 60-Irrigation Service	251	323	158	272	1,189	6,247	5,588	5,829	3,799	7,681	5,522	2,294	624	39,153
21 TY TOTAL	1,673,220	1,912,842	1,816,595	1,345,808	915,103	589,174	499,110	454,926	478,590	1,287,345	2,016,577	4,444,458	6,222,437	17,433,749
22 Total Sales	1,673,220	1,912,842	1,816,595	1,345,808	915,103	589,174	499,110	454,926	478,590	1,287,345	2,016,577	4,444,458	6,222,437	17,433,749
23 Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0	0

SCGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	FY2001
PGA Revenue														
1 10-Residential	(23,215)	1,458	408	3,455	3,365	993	1,122	1,041	1,120	23,941	32,664	90,215	150,990	136,568
2 11-Residential A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 12-CARES	(5,526)	333	93	782	565	280	259	249	272	5,947	7,787	21,501	31,855	32,543
4 13-CARES Med Life Support	(4)	0	0	1	0	0	0	0	0	4	13	22	23	37
5 20-Sm Vol Commercial	(8,820)	337	231	1,587	1,103	746	670	700	718	16,503	21,805	37,491	52,960	73,072
6 21-Sm Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 22-Lg Vol Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 30-Sm Vol Industrial	(764)	18	20	43	144	149	0	0	0	1,447	81	2,945	4,586	4,084
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 40-Sm Vol Pub Auth	(3,543)	137	107	456	260	176	71	80	108	1,695	4,569	9,668	21,278	13,783
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19 44-Gas Light Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20 60-Irrigation Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21 TY TOTAL	(41,872)	2,284	859	6,323	5,438	2,345	2,123	2,071	2,219	49,537	66,919	161,842	261,692	260,087
22 Total Sales	(41,872)	2,284	859	6,323	5,438	2,345	2,123	2,071	2,219	49,537	66,919	161,842	261,692	260,087
23 Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Citizens Communication Company - NAGD
Sales and Demand Model
Example of Normalization Calculations

Class Number = 1
Correlation of sales and DD = 96%

10-Residential

Line No.	Month	Billing Cycle Customers	Billing Cycle Sales	Base Load	Heating Load	Monthly Actual Degree Days	Monthly Normal Degree Days	Colder (Warmer) Than Normal	Actual Unit Heat Load Therms/DD	Weather Adjustment	Normal Heat Load	Normal Firm Billing Cycle Therms	Average Use Per Customer	Weath Adj Billing Block Rate	Base Rate Revenue Weath Adjustment	Headblock Therm Adj	Tailblock Therm Adj	PGA Gas Rate, $/th	PGA Revenue Adjustment
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)
1	Jan-01	96,059	10,131,903	1,458,786	8,673,117	839	856	(18)	10,342	182,813	8,855,930	10,314,716	105	$ 0.44140	$80,694	0	182,813	$ 0.10685	$19,534
2	Feb-01	97,014	10,956,521	1,473,289	9,483,232	937	823	114	10,121	(1,156,760)	8,326,472	9,799,761	113	$ 0.44140	($510,594)	0	(1,156,760)	$ 0.11296	($130,668)
3	Mar-01	97,592	10,080,842	1,482,067	8,598,775	802	753	48	10,726	(519,144)	8,079,631	9,561,698	103	$ 0.44140	($229,150)	0	(519,144)	$ 0.11735	($60,923)
4	Apr-01	98,333	6,413,180	1,493,320	4,919,860	479	522	(43)	10,265	442,023	5,361,883	6,855,203	65	$ 0.44140	$195,109	0	442,023	$ 0.13053	$57,696
5	May-01	98,417	3,939,921	1,494,596	2,445,325	254	287	(33)	9,614	314,655	2,759,981	4,254,576	40	$ 0.44140	$138,889	0	314,655	$ 0.14018	$44,109
6	Jun-01	99,005	2,029,971	1,503,525	526,446	49	119	(69)	6,540	454,065	980,510	2,484,036	21	$ 0.44140	$200,424	0	454,065	$ 0.14627	$66,417
7	Jul-01	98,380	1,554,326	1,494,034	60,292	17	28	(10)	3,467	35,701	95,993	1,590,027	16	$ 0.44140	$15,758	0	35,701	$ 0.15031	$5,366
8	Aug-01	99,896	1,456,764	1,456,764	0	15	13	2	0	0	0	1,456,764	15	$ 0.44140	$0	0	0	$ 0.15071	$0
9	Sep-01	99,117	1,536,582	1,505,226	31,356	35	49	(14)	891	12,239	43,595	1,548,821	16	$ 0.44140	$5,402	0	12,239	$ 0.15073	$1,845
10	Oct-01	99,762	1,901,262	1,515,021	386,241	147	207	(60)	2,633	159,191	545,432	2,060,453	19	$ 0.44140	$70,267	0	159,191	$ 0.34326	$54,645
11	Nov-01	100,030	3,372,582	1,519,091	1,853,491	391	555	(164)	4,739	776,789	2,630,280	4,149,371	34	$ 0.44140	$342,875	0	776,789	$ 0.34336	$266,719
12	Dec-01	100,938	8,212,379	1,532,880	6,679,499	836	788	48	7,988	(383,452)	6,296,046	7,828,927	81	$ 0.44140	($169,256)	0	(383,452)	$ 0.34344	($131,694)
13	Jan-02	101,510	11,805,746	1,541,567	10,264,179	939	934	5	10,929	(58,458)	10,205,721	11,747,288	116	$ 0.44140	($25,803)	0	(58,458)	$ 0.34346	($20,078)
14	TY TOTAL	91,119	61,586,233	17,928,600	43,657,633	4,802	5,000	(199)		318,120	43,975,753	61,904,353	627		$140,418	0	318,120		193,046
15	6 Month Winter	98,340	53,107,328	10,454,030	42,653,298	4,538	4,585	(47)		(343,076)	42,310,223	52,764,252	542		($151,434)	0	(343,076)		64,773
16	6 Month Summer	99,232	8,478,905	7,474,570	1,004,335	263	415	(152)		661,195	1,665,530	9,140,100	85		$291,852	0	661,195		128,273

NOTES:

		Input	Input	See testimony	(4)-(3)	Lookup	Lookup	(6)-(7)	(5)/(6)	-(8)*(9)	(5)+(10)	(3)-(5)+(11)	(3)/(2)	Lookup based on (13)	(10)*(14)	0 or (10)	0 or (10)	Input	(10)*(18)

Citizens Communication Company
Sales and Demand Model
Weather Normalized Sales Volumes

NAGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	TY TOTAL
BILLING MONTH NORMALIZED SALES, Therms														
1 10-Residential	10,314,716	9,799,761	9,561,698	6,855,203	4,254,576	2,484,036	1,590,027	1,456,764	1,548,821	2,060,453	4,149,371	7,828,927	11,747,288	61,904,353
2 11-Residential A/C	801	749	724	461	313	158	228	254	182	178	116	422	638	4,585
3 12-CARES	111,033	135,100	129,762	95,301	56,437	37,010	22,943	20,230	21,838	31,291	55,103	108,354	173,902	824,400
4 13-CARES Med Life Support	155	132	123	70	35	20	15	13	13	16	65	116	147	774
5 20-Sm Vol Commercial	3,734,918	3,632,058	3,492,198	2,718,784	1,799,873	1,619,645	1,204,390	1,110,858	1,150,159	1,328,040	1,898,081	3,014,127	4,086,730	26,703,131
6 21-Sm Vol Commercial A/C	2,560	2,635	2,320	1,649	1,509	2,596	2,763	2,618	2,289	1,844	1,962	2,071	2,776	26,816
7 22-Lg Vol Commercial	382,443	256,927	236,459	215,004	145,576	148,561	82,079	71,920	81,914	112,812	173,490	235,617	283,930	2,142,803
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	253,883	215,064	222,971	201,281	164,651	146,742	134,145	132,869	126,916	177,578	204,585	253,659	264,387	2,234,344
10 30-Sm Vol Industrial	71,608	119,867	109,025	128,771	59,928	56,895	67,659	43,874	77,000	53,889	59,771	94,662	98,204	942,949
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	327,400	272,787	248,373	273,423	242,164	236,961	208,711	143,935	167,515	205,608	277,938	267,657	464,297	2,872,472
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	1,363,084	1,117,094	1,103,212	1,356,987	1,356,688	1,111,210	1,147,399	1,355,385	1,579,366	1,031,195	1,033,303	1,355,023	1,363,084	14,909,946
15 40-Sm Vol Pub Auth	874,264	838,494	818,967	554,724	294,130	194,383	135,682	94,366	82,820	128,715	319,705	694,083	975,638	5,030,332
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	130,049	176,311	113,275	146,735	72,097	52,167	24,193	23,482	27,093	42,592	88,931	133,178	190,067	1,030,103
18 T1-Lg Vol Pub Auth Transp	641,887	534,759	575,821	524,397	389,478	300,972	259,980	249,647	285,291	459,873	572,339	643,690	675,656	5,438,134
19 44-Gas Light Service	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,844	8,690	8,646	106,194
20 60-Irrigation Service	2,344	2,860	1,348	2,085	8,476	42,642	37,102	38,614	25,159	22,361	16,077	6,679	1,818	205,747
21 Total	18,220,011	17,113,463	16,625,143	13,083,740	8,854,797	6,442,863	4,926,182	4,753,695	5,185,241	5,665,312	8,859,680	14,646,954	20,337,207	124,377,082
22 Total Sales	15,961,157	15,246,546	14,723,138	11,001,075	6,943,979	4,883,939	3,384,659	3,015,794	3,193,668	3,996,667	7,049,453	12,394,582	18,034,080	101,794,658
23 Total Transportation	2,258,854	1,866,917	1,902,005	2,082,665	1,910,818	1,558,923	1,541,524	1,737,901	1,991,573	1,668,645	1,810,227	2,252,372	2,303,127	22,582,424

SCGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	TY TOTAL
BILLING MONTH NORMALIZED SALES, Therms														
1 10-Residential	500,692	498,170	363,700	272,810	210,032	75,428	86,835	80,889	86,849	96,821	161,683	304,215	540,126	2,738,125
2 11-Residential A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 12-CARES	119,413	113,838	82,959	62,079	34,732	22,004	20,060	19,369	21,051	25,943	40,695	71,960	114,900	634,102
4 13-CARES Med Life Support	81	86	61	49	24	16	15	14	16	19	77	69	87	529
5 20-Sm Vol Commercial	193,201	218,746	136,285	125,322	80,718	57,943	51,034	53,250	54,666	76,248	116,904	128,646	190,803	1,292,962
6 21-Sm Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 22-Lg Vol Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 30-Sm Vol Industrial	16,125	11,641	11,050	3,688	10,851	11,302	33	30	9	5,440	610	9,147	16,781	79,927
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 40-Sm Vol Pub Auth	77,073	87,083	60,316	36,666	18,216	13,870	5,375	6,112	8,217	6,348	27,563	32,319	75,707	379,157
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19 44-Gas Light Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20 60-Irrigation Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21 Total	906,585	929,563	654,370	500,614	354,573	180,563	163,353	159,664	170,808	210,820	347,532	546,356	938,404	5,124,802
22 Total Sales	906,585	929,563	654,370	500,614	354,573	180,563	163,353	159,664	170,808	210,820	347,532	546,356	938,404	5,124,802
23 Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Citizens Communication Company
Sales and Demand Model
Weather Normalized Base Revenues

NAGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	TY TOTAL
Normalized Base Revenue (Excludes PGA Revenues)														
1 10-Residential	5,017,960	4,701,238	4,692,260	3,504,571	2,361,084	1,575,685	1,177,499	1,136,363	1,176,846	1,361,856	2,327,676	3,956,311	5,676,645	32,989,350
2 11-Residential A/C	382	361	349	232	167	97	120	130	103	96	76	211	306	2,324
3 12-CARES	55,282	66,558	65,010	50,073	32,854	24,251	17,914	16,872	17,441	21,478	31,603	55,348	85,359	454,684
4 13-CARES Med Life Support	74	63	59	36	21	14	11	11	11	12	34	56	70	402
5 20-Sm Vol Commercial	1,497,991	1,440,595	1,404,432	1,105,253	756,412	682,294	528,159	492,198	506,991	555,185	795,248	1,226,528	1,631,152	10,991,286
6 21-Sm Vol Commercial A/C	1,013	1,041	920	663	609	922	976	929	817	666	783	825	1,095	10,164
7 22-Lg Vol Commercial	129,974	88,330	81,371	74,076	50,471	51,486	28,882	25,428	28,826	39,331	59,887	81,010	97,436	739,072
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	24,575	21,082	21,793	19,841	16,545	14,933	13,799	13,684	13,148	17,708	20,139	24,555	25,521	221,802
10 30-Sm Vol Industrial	21,438	41,610	33,441	43,107	20,995	19,896	20,700	15,490	26,330	18,942	21,016	33,011	34,206	315,977
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	101,191	84,386	76,874	84,582	74,964	73,363	64,670	44,739	51,994	63,716	85,971	82,808	115,016	889,260
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	64,465	54,300	58,975	61,987	59,637	53,214	55,131	61,907	65,064	53,381	53,413	60,716	64,465	702,190
15 40-Sm Vol Pub Auth	333,836	317,267	311,830	212,654	116,194	79,047	54,763	41,708	37,473	53,408	126,968	263,022	354,345	1,948,171
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	42,140	57,169	36,808	42,075	23,391	17,141	8,149	7,941	9,107	13,207	29,037	43,298	61,634	329,465
18 T1-Lg Vol Pub Auth Transp	45,793	38,123	40,737	36,729	27,003	20,125	17,456	17,073	19,312	32,294	40,225	45,627	48,234	380,495
19 44-Gas Light Service	3,960	3,960	3,960	3,960	3,960	3,960	3,960	3,960	3,960	3,960	3,960	3,901	914	47,456
20 60-Irrigation Service	2,344	2,860	1,348	2,085	8,476	42,642	37,102	38,614	25,159	22,361	16,077	6,679	1,818	205,747
21 Total	7,342,416	6,918,943	6,830,169	5,241,924	3,552,781	2,659,068	2,029,292	1,917,046	1,982,583	2,257,601	3,612,114	5,883,906	8,198,217	50,227,844
22 Total Sales	7,207,584	6,805,439	6,708,664	5,123,367	3,449,597	2,570,796	1,942,906	1,824,382	1,885,059	2,154,217	3,498,337	5,753,008	8,059,997	48,923,357
23 Total Transportation	134,833	113,504	121,505	118,557	103,184	88,272	86,385	92,664	97,525	103,384	113,777	130,898	138,220	1,304,487

SCGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	TY TOTAL
Normalized Base Revenue (Excludes PGA Revenues)														
1 10-Residential	349,430	320,462	243,655	191,477	159,877	89,193	79,590	78,159	81,611	85,655	125,300	210,942	378,433	2,015,350
2 11-Residential A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 12-CARES	78,385	74,853	57,798	45,994	28,970	21,693	20,445	19,950	21,050	24,352	34,138	51,747	38,389	479,374
4 13-CARES Med Life Support	56	58	44	37	22	16	16	15	16	18	53	49	31	399
5 20-Sm Vol Commercial	105,698	119,249	75,688	70,136	46,293	33,561	29,616	30,666	31,409	42,802	64,680	71,360	96,981	721,157
6 21-Sm Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 22-Lg Vol Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 30-Sm Vol Industrial	8,134	5,876	5,575	1,913	5,481	5,705	26	25	11	2,776	346	4,630	7,412	40,498
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 40-Sm Vol Pub Auth	39,820	45,024	31,392	19,624	10,063	7,668	3,299	3,680	4,757	3,813	14,960	17,278	34,783	201,378
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19 44-Gas Light Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20 60-Irrigation Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21 Total	581,523	565,523	414,152	329,180	250,705	157,836	132,991	132,495	138,854	159,416	239,477	356,004	556,029	3,458,156
22 Total Sales	581,523	565,523	414,152	329,180	250,705	157,836	132,991	132,495	138,854	159,416	239,477	356,004	556,029	3,458,156
23 Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Citizens Communication Company
Sales and Demand Model
Weather Normalized PGA Revenues

NAGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	TY TOTAL
Weather														
Normalized PGA Revenue														
1 10-Residential	1,102,146	1,106,984	1,122,092	894,784	596,413	363,347	239,003	219,552	233,448	707,279	1,424,733	2,688,781	4,034,719	10,698,562
2 11-Residential A/C	86	85	85	60	44	23	34	38	27	61	40	145	219	728
3 12-CARES	11,863	15,260	15,227	12,438	7,910	5,412	3,447	3,048	3,290	10,740	18,919	37,212	59,727	144,765
4 13-CARES Med Life Support	17	15	14	9	5	3	2	2	2	6	22	40	50	137
5 20-Sm Vol Commercial	399,229	410,386	409,942	355,028	252,483	237,235	181,352	167,712	173,646	456,148	651,948	1,035,310	1,403,747	4,730,417
6 21-Sm Vol Commercial A/C	274	298	272	215	212	380	416	395	346	633	674	711	954	4,827
7 22-Lg Vol Commercial	40,883	29,033	27,760	28,079	20,424	21,764	12,361	10,860	12,369	38,751	59,594	80,934	97,530	382,813
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 30-Sm Vol Industrial	7,655	13,545	12,799	16,817	8,408	8,335	10,189	6,625	11,627	18,511	20,531	32,516	33,733	167,559
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	34,999	30,825	29,159	35,709	33,976	34,715	31,432	21,734	25,295	70,626	95,472	91,940	159,486	535,882
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 40-Sm Vol Pub Auth	93,455	94,746	96,143	72,443	41,263	28,473	20,431	14,247	12,503	44,210	109,814	238,414	335,128	866,140
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	13,902	19,923	13,298	14,846	10,115	7,642	3,644	3,546	4,091	14,630	30,548	45,747	65,288	181,933
18 T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19 44-Gas Light Service	948	1,002	1,041	1,158	1,244	1,299	1,335	1,339	1,339	3,045	3,038	3,002	2,970	19,790
20 60-Irrigation Service	251	323	158	272	1,189	6,247	5,588	5,831	3,799	7,681	5,522	2,294	624	39,155
21 Total	1,705,706	1,722,423	1,727,991	1,431,859	973,685	714,875	509,234	454,928	481,782	1,372,323	2,420,855	4,257,048	6,194,176	17,772,708
22 Total Sales	1,705,706	1,722,423	1,727,991	1,431,859	973,685	714,875	509,234	454,928	481,782	1,372,323	2,420,855	4,257,048	6,194,176	17,772,708
23 Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0	0

SCGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Jan-02	TY TOTAL
Weather														
Normalized PGA Revenue														
1 10-Residential	(23,195)	1,267	348	3,603	3,330	993	1,122	1,041	1,120	25,836	43,152	81,234	144,242	139,852
2 11-Residential A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 12-CARES	(5,532)	290	79	820	551	290	259	249	272	6,923	10,861	19,215	30,684	34,276
4 13-CARES Med Life Support	(4)	0	0	1	0	0	0	0	0	5	21	18	23	43
5 20-Sm Vol Commercial	(8,867)	296	203	1,654	1,069	763	670	700	718	20,364	31,222	34,359	50,962	83,152
6 21-Sm Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 22-Lg Vol Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 30-Sm Vol Industrial	(740)	16	16	49	144	149	0	0	0	1,453	163	2,443	4,482	3,693
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 40-Sm Vol Pub Auth	(3,537)	118	90	484	241	183	71	80	108	1,695	7,361	8,632	20,221	15,526
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19 44-Gas Light Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20 60-Irrigation Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21 Total	(41,876)	1,987	736	6,610	5,335	2,378	2,123	2,071	2,219	56,276	92,781	145,902	250,614	276,542
22 Total Sales	(41,876)	1,987	736	6,610	5,335	2,378	2,123	2,071	2,219	56,276	92,781	145,902	250,614	276,542
23 Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Citizens Communications Company
Northern Area Gas Division
Analysis of NSAM Revenue

Line No.	Class/Rate	Revenue Including NSAM	NSAM Premium	Revenue Excluding NSAM
	(1)	(2)	(3)	(4)
1	RESIDENTIAL			
2	Residential Service	$44,304,411	$ 949,962	$43,354,448
3	Residential Service Air Conditioning	3,356	245	3,112
4	C.A.R.E.S.	597,269	4,071	593,198
5	C.A.R.E.S. Medical Life Support	518		518
6	Total Residential	$44,905,554	$954,278	$43,951,276
7				
8	COMMERCIAL			
9	Small Volume Commercial	$15,804,340	$ 252,553	$15,551,787
10	Small Volume Commercial Air Conditioning	14,991		14,991
11	Large Volume Commercial	1,070,057		1,070,057
12	Large Volume Commercial Air Conditioning	0		0
13	Total Commercial	$16,889,388	$252,553	$16,636,835
14				
15	INDUSTRIAL			
16	Small Volume Industrial	$483,536		$483,536
17	Small Volume Industrial Air Conditioning	0		0
18	Large Volume Industrial	1,385,297		1,385,297
19	Large Volume Industrial Air Conditioning	0		0
20	Total Industrial	$1,868,833	$0	$1,868,833
21				
22	Public Authority			
23	Small Volume Public Authority	$2,834,066	$ 35,023	$2,799,043
24	Small Volume Public Authority Air Conditioning	0		0
25	Large Volume Public Authority	486,422		486,422
26	Large Volume Public Authority Air Conditioning	0		0
27	Total Public Authority	$3,320,488	$35,023	$3,285,464
28				
29	Special Gas Light Service	$67,246		$67,246
30				
31	Irrigation	$103,015		$103,015
32				
33	Cogenration Rate	$0		$0
34				
35	Total Transportation Rate	$1,293,575		$1,293,575
36				
37	Grand Total	$68,448,098	$1,241,854	$67,206,244

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Citizens Communication Company
Sales and Demand Model
Weather Normalized Calendar Month Sales Volumes

NAGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TY TOTAL
CALENDAR MONTH NORMALIZED													
SALES, Therms													
1 10-Residential	10,659,919	8,589,330	8,137,139	5,876,469	3,401,983	2,022,143	1,530,425	1,492,292	1,687,539	2,956,521	5,709,329	9,831,471	61,894,559
2 11-Residential A/C	836	657	668	439	276	171	235	238	182	169	159	478	4,508
3 12-CARES	131,139	118,025	110,493	80,614	47,293	29,538	21,696	20,866	24,435	41,943	77,848	142,310	846,200
4 13-CARES Med Life Support	134	109	81	46	23	15	13	13	15	51	108	141	751
5 20-Sm Vol Commercial	3,906,980	3,157,491	3,041,859	2,341,150	1,719,252	1,387,256	1,161,610	1,126,504	1,200,468	1,611,951	2,384,359	3,600,797	26,639,677
6 21-Sm Vol Commercial A/C	2,772	2,176	1,922	1,589	2,047	2,589	2,735	2,458	2,070	1,988	1,990	2,444	26,781
7 22-Lg Vol Commercial	312,558	214,127	217,124	178,876	149,078	101,536	75,181	76,958	95,704	152,102	212,623	271,965	2,057,833
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	253,883	215,064	222,971	201,281	164,651	146,742	134,145	132,869	126,916	177,578	204,585	253,659	2,234,344
10 30-Sm Vol Industrial	97,706	105,726	110,805	105,060	58,820	60,210	59,522	52,213	71,442	56,215	70,902	103,514	952,134
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	307,084	229,288	251,485	264,117	244,439	220,429	175,752	154,621	177,099	241,196	278,958	370,994	2,915,462
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	1,363,084	1,117,094	1,103,212	1,356,987	1,356,688	1,111,210	1,147,399	1,355,385	1,579,366	1,031,195	1,033,303	1,355,023	14,909,946
15 40-Sm Vol Pub Auth	908,067	739,961	673,844	447,495	246,233	162,961	116,913	89,405	100,209	209,976	480,796	848,573	5,024,434
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	176,885	111,164	133,737	101,821	57,455	32,679	23,844	25,031	34,710	72,306	117,810	172,411	1,059,853
18 T1-Lg Vol Pub Auth Transp	641,887	534,759	575,821	524,397	389,478	300,972	259,980	249,647	285,291	459,873	572,339	643,690	5,438,134
19 44-Gas Light Service	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,844	8,690	106,194
20 60-Irrigation Service	2,636	2,178	1,490	3,549	16,089	40,982	37,763	35,337	25,040	21,320	13,478	5,611	205,472
21 Total	18,774,435	15,146,018	14,591,519	11,492,755	7,862,673	5,628,300	4,756,078	4,822,702	5,419,351	7,043,249	11,167,433	17,611,772	124,316,284
22 Total Sales	16,515,581	13,279,101	12,689,514	9,410,090	5,951,855	4,069,376	3,214,554	3,084,801	3,427,779	5,374,604	9,357,205	15,359,400	101,733,860
23 Total Transportation	2,258,854	1,866,917	1,902,005	2,082,665	1,910,818	1,558,923	1,541,524	1,737,901	1,991,573	1,668,645	1,810,227	2,252,372	22,582,424

SCGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TY TOTAL
CALENDAR MONTH NORMALIZED													
SALES, Therms													
1 10-Residential	533,313	381,702	311,837	265,309	131,611	81,939	81,489	83,697	88,335	120,587	223,158	421,296	2,724,273
2 11-Residential A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
3 12-CARES	123,763	87,510	70,442	52,788	26,997	20,989	19,298	20,208	21,885	31,509	54,673	94,761	624,823
4 13-CARES Med Life Support	85	76	54	45	20	16	15	14	15	27	80	86	533
5 20-Sm Vol Commercial	221,659	154,901	126,460	109,799	66,584	53,388	52,331	53,754	59,893	92,554	126,578	162,265	1,280,167
6 21-Sm Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
7 22-Lg Vol Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
10 30-Sm Vol Industrial	14,885	10,734	7,632	8,402	10,529	5,555	31	23	745	4,845	3,273	13,188	79,843
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
15 40-Sm Vol Pub Auth	88,400	65,380	47,116	30,227	15,279	9,025	5,863	7,119	7,097	13,623	31,056	53,775	373,962
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	0	0	0	0	0	0	0	0	0	0	0	0	0
18 T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
19 44-Gas Light Service	0	0	0	0	0	0	0	0	0	0	0	0	0
20 60-Irrigation Service	0	0	0	0	0	0	0	0	0	0	0	0	0
21 Total	982,106	700,304	563,542	466,570	251,020	170,913	159,026	164,816	177,971	263,144	438,817	745,373	5,083,601
22 Total Sales	982,106	700,304	563,542	466,570	251,020	170,913	159,026	164,816	177,971	263,144	438,817	745,373	5,083,601
23 Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0

Citizens Communication Company
Sales and Demand Model
Weather Normalized Calendar Month Base Revenues

NAGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TY TOTAL
Normalized Base Revenue (Excludes PGA Revenues)													
1 10-Residential	5,169,822	4,180,473	4,065,879	3,074,411	1,986,547	1,374,742	1,151,799	1,151,895	1,237,863	1,737,185	3,014,736	4,839,194	32,984,545
2 11-Residential A/C	397	321	325	222	151	102	123	124	103	93	95	236	2,291
3 12-CARES	64,129	59,146	56,516	43,617	28,835	20,971	17,371	17,151	18,586	25,989	41,645	70,264	464,220
4 13-CARES Med Life Support	64	53	41	25	15	12	11	11	12	27	53	67	391
5 20-Sm Vol Commercial	1,563,824	1,261,496	1,232,334	961,565	725,669	594,433	511,857	498,151	526,155	658,977	981,017	1,451,365	10,966,843
6 21-Sm Vol Commercial A/C	1,094	865	768	640	816	919	966	874	742	716	794	968	10,162
7 22-Lg Vol Commercial	106,415	73,778	74,797	61,793	51,662	35,497	26,537	27,141	33,514	52,690	73,192	93,368	710,384
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	24,575	21,082	21,793	19,841	16,545	14,933	13,799	13,684	13,148	17,708	20,139	24,555	221,802
10 30-Sm Vol Industrial	29,106	36,757	33,981	35,257	20,614	21,033	18,265	18,362	24,465	19,742	24,851	36,060	318,494
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	94,940	71,002	77,832	81,719	75,664	68,276	54,529	48,027	54,943	74,666	86,285	114,605	902,488
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	64,465	54,300	58,975	61,987	59,637	53,214	55,131	61,907	65,064	53,381	53,413	60,716	702,190
15 40-Sm Vol Pub Auth	346,503	280,716	257,667	172,781	98,286	67,289	48,057	39,850	44,000	82,997	187,698	320,097	1,945,942
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	57,208	36,184	43,390	29,311	18,717	10,878	8,036	8,440	11,562	22,159	38,345	55,943	340,173
18 T1-Lg Vol Pub Auth Transp	45,793	38,123	40,737	36,729	27,003	20,125	17,456	17,073	19,312	32,294	40,225	45,627	380,495
19 44-Gas Light Service	3,960	3,960	3,960	3,960	3,960	3,960	3,960	3,960	3,960	3,960	3,960	3,901	47,456
20 60-Irrigation Service	677	722	514	1,146	4,943	12,645	11,687	10,941	7,767	5,138	5,176	2,185	63,541
21 Total	7,572,972	6,118,976	5,969,509	4,585,003	3,119,062	2,299,028	1,939,583	1,917,590	2,061,196	2,787,722	4,571,623	7,119,152	50,061,416
22 Total Sales	7,438,139	6,005,472	5,848,004	4,466,447	3,015,878	2,210,756	1,853,198	1,824,926	1,963,672	2,684,338	4,457,847	6,988,254	48,756,930
23 Total Transportation	134,833	113,504	121,505	118,557	103,184	88,272	86,385	92,664	97,525	103,384	113,777	130,898	1,304,487

SCGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TY TOTAL
Normalized Base Revenue (Excludes PGA Revenues)													
1 10-Residential	366,811	258,408	213,605	187,130	114,440	93,638	75,940	80,076	82,626	101,879	167,269	278,778	2,020,600
2 11-Residential A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
3 12-CARES	80,906	59,599	50,546	40,611	23,689	21,000	19,924	20,523	21,619	28,152	43,681	64,958	475,207
4 13-CARES Med Life Support	58	53	40	34	19	16	15	15	16	24	54	59	402
5 20-Sm Vol Commercial	120,861	85,233	70,453	61,866	38,762	31,134	30,368	30,958	34,194	51,489	69,834	89,272	714,424
6 21-Sm Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
7 22-Lg Vol Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
10 30-Sm Vol Industrial	7,502	5,414	3,834	4,314	5,317	2,777	25	21	514	2,473	1,765	6,689	40,644
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
15 40-Sm Vol Pub Auth	45,590	33,969	24,668	16,344	8,498	5,087	3,581	4,264	4,160	8,029	16,821	28,207	199,219
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	0	0	0	0	0	0	0	0	0	0	0	0	0
18 T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
19 44-Gas Light Service	0	0	0	0	0	0	0	0	0	0	0	0	0
20 60-Irrigation Service	0	0	0	0	0	0	0	0	0	0	0	0	0
21 Total	621,727	442,675	363,147	310,299	190,725	153,653	129,853	135,856	143,129	192,045	299,424	467,963	3,450,496
22 Total Sales	621,727	442,675	363,147	310,299	190,725	153,653	129,853	135,856	143,129	192,045	299,424	467,963	3,450,496
23 Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0

Citizens Communication Company
Sales and Demand Model
Weather Normalized Calendar Month PGA Revenues

NAGD Weather Normalized PGA Revenue	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TY TOTAL
1 10-Residential	1,139,032	970,253	954,916	767,033	476,895	295,784	230,044	224,907	254,357	1,014,866	1,960,362	3,376,539	11,664,989
2 11-Residential A/C	89	74	78	57	39	25	35	36	27	58	55	164	739
3 12-CARES	14,011	13,331	12,966	10,521	6,628	4,319	3,260	3,144	3,682	14,396	26,729	48,874	161,860
4 13-CARES Med Life Support	14	12	10	6	3	2	2	2	2	17	37	49	157
5 20-Sm Vol Commercial	417,621	356,764	357,077	305,715	241,174	203,196	174,910	170,074	181,241	553,665	818,974	1,236,823	5,017,233
6 21-Sm Vol Commercial A/C	296	246	226	207	287	379	412	371	313	683	684	840	4,943
7 22-Lg Vol Commercial	33,412	24,196	25,490	23,361	20,916	14,875	11,322	11,621	14,451	52,247	73,036	93,420	398,348
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
10 30-Sm Vol Industrial	10,445	11,947	13,008	13,721	8,252	8,821	8,964	7,884	10,788	19,310	24,355	35,557	173,051
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	32,827	25,910	29,524	34,494	34,295	32,293	26,468	23,348	26,742	82,851	95,822	127,437	572,010
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
15 40-Sm Vol Pub Auth	97,068	83,613	79,106	58,439	34,543	23,870	17,604	13,498	15,128	72,121	165,146	291,480	951,618
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	18,909	12,562	15,701	10,302	8,061	4,788	3,591	3,780	5,241	24,837	40,468	59,223	207,461
18 T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
19 44-Gas Light Service	948	1,002	1,041	1,158	1,244	1,299	1,335	1,339	1,339	3,045	3,038	3,002	19,790
20 60-Irrigation Service	282	246	175	463	2,257	6,004	5,687	5,336	3,781	7,323	4,630	1,927	38,111
21 Total	1,764,954	1,500,156	1,489,318	1,225,478	834,594	595,655	483,635	465,337	517,092	1,845,420	3,213,335	5,275,335	19,210,311
22 Total Sales	1,764,954	1,500,156	1,489,318	1,225,478	834,594	595,655	483,635	465,337	517,092	1,845,420	3,213,335	5,275,335	19,210,311
23 Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0

SCGD Weather Normalized PGA Revenue	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TY TOTAL
1 10-Residential	(24,707)	971	298	3,504	2,087	1,079	1,053	1,078	1,140	32,178	59,560	112,498	190,737
2 11-Residential A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
3 12-CARES	(5,734)	223	67	697	428	276	249	260	282	8,408	14,592	25,304	45,053
4 13-CARES Med Life Support	(4)	0	0	1	0	0	0	0	0	7	21	23	49
5 20-Sm Vol Commercial	(10,173)	210	189	1,449	882	703	688	706	787	24,718	33,806	43,339	97,303
6 21-Sm Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
7 22-Lg Vol Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
10 30-Sm Vol Industrial	(683)	15	11	111	139	73	0	0	10	1,294	874	3,522	5,367
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
15 40-Sm Vol Pub Auth	(4,057)	89	70	399	202	119	77	94	93	3,638	8,294	14,363	23,381
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	0	0	0	0	0	0	0	0	0	0	0	0	0
18 T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
19 44-Gas Light Service	0	0	0	0	0	0	0	0	0	0	0	0	0
20 60-Irrigation Service	0	0	0	0	0	0	0	0	0	0	0	0	0
21 Total	(45,358)	1,507	635	6,161	3,739	2,251	2,067	2,138	2,312	70,243	117,147	199,048	361,891
22 Total Sales	(45,358)	1,507	635	6,161	3,739	2,251	2,067	2,138	2,312	70,243	117,147	199,048	361,891
23 Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0

Citizens Communication Company
Sales and Demand Model
Year End Customer Adjustment - Billed Customers

NAGD CUSTOMERS	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TY TOTAL
1 10-Residential	96,059	97,014	97,592	98,333	98,417	99,005	98,380	99,896	99,117	99,762	100,030	100,938	1,184,543
2 11-Residential A/C	6	6	6	6	6	6	6	6	6	6	5	5	70
3 12-CARES	1,285	1,582	1,563	1,635	1,610	1,601	1,583	1,602	1,564	1,645	1,455	1,550	18,675
4 13-CARES Med Life Support	1	1	1	1	1	1	1	1	1	1	1	1	12
5 20-Sm Vol Commercial	9,197	9,317	9,318	9,436	9,343	9,325	9,227	9,272	9,182	9,291	9,352	9,518	111,778
6 21-Sm Vol Commercial A/C	4	4	4	4	4	4	4	4	4	4	4	4	48
7 22-Lg Vol Commercial	14	13	13	13	13	13	13	13	13	13	12	12	155
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	9	9	9	9	9	9	9	9	9	9	9	9	108
10 30-Sm Vol Industrial	16	19	16	19	14	15	18	15	20	16	17	16	201
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	6	6	6	6	6	6	6	6	6	6	6	6	72
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	11	11	11	11	11	11	10	10	10	10	10	10	126
15 40-Sm Vol Pub Auth	828	830	823	851	830	841	838	848	852	872	859	880	10,152
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	4	5	5	5	5	5	5	5	5	5	5	5	59
18 T1-Lg Vol Pub Auth Transp	6	6	6	6	6	6	6	6	6	6	6	6	72
19 44-Gas Light Service	4	4	4	4	4	4	4	4	4	4	4	4	48
20 60-Irrigation Service	8	8	9	7	7	10	7	7	7	7	7	7	91
21 Total	107,458	108,835	109,386	110,346	110,286	110,862	110,117	111,704	110,806	111,657	111,782	112,971	1,326,210
22 Total Sales	107,432	108,809	109,360	110,320	110,260	110,836	110,092	111,679	110,781	111,632	111,757	112,946	1,325,904
23 Total Transportation	26	26	26	26	26	26	25	25	25	25	25	25	306

SCGD CUSTOMERS	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TY TOTAL
1 10-Residential	4,989	4,972	4,986	5,032	5,065	4,981	5,025	4,992	4,996	5,103	5,177	5,082	60,399
2 11-Residential A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
3 12-CARES	1,370	1,370	1,370	1,370	1,370	1,370	1,370	1,370	1,370	1,370	1,370	1,370	16,441
4 13-CARES Med Life Support	1	1	1	1	1	1	1	1	1	1	1	1	12
5 20-Sm Vol Commercial	586	586	575	538	570	548	549	554	546	551	562	544	6,709
6 21-Sm Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
7 22-Lg Vol Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
10 30-Sm Vol Industrial	3	3	3	3	3	3	1	1	1	3	2	3	29
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
15 40-Sm Vol Pub Auth	68	67	77	64	70	69	73	76	74	82	80	66	866
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	0	0	0	0	0	0	0	0	0	0	0	0	0
18 T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
19 44-Gas Light Service	0	0	0	0	0	0	0	0	0	0	0	0	0
20 60-Irrigation Service	0	0	0	0	0	0	0	0	0	0	0	0	0
21 Total	7,017	6,999	7,012	7,008	7,079	6,972	7,019	6,994	6,988	7,110	7,192	7,066	84,456
22 Total Sales	7,017	6,999	7,012	7,008	7,079	6,972	7,019	6,994	6,988	7,110	7,192	7,066	84,456
23 Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0

Citizens Communication Company
Sales and Demand Model
Year End Customer Percentge Adjustment

NAGD Customer Adj Percentage	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
1 10-Residential	5.08%	4.04%	3.43%	2.65%	2.56%	1.95%	2.60%	1.04%	1.84%	1.18%	0.91%	0.00%
2 11-Residential A/C	-16.67%	-16.67%	-16.67%	-16.67%	-16.67%	-16.67%	-16.67%	-16.67%	-16.67%	-16.67%	0.00%	0.00%
3 12-CARES	20.62%	-2.02%	-0.83%	-5.20%	-3.73%	-3.19%	-2.08%	-3.25%	-0.90%	-5.78%	6.53%	0.00%
4 13-CARES Med Life Support	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5 20-Sm Vol Commercial	3.49%	2.16%	2.15%	0.87%	1.87%	2.07%	3.15%	2.65%	3.66%	2.44%	1.78%	0.00%
6 21-Sm Vol Commercial A/C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
7 22-Lg Vol Commercial	-14.29%	-7.69%	-7.69%	-7.69%	-7.69%	-7.69%	-7.69%	-7.69%	-7.69%	-7.69%	0.00%	0.00%
8 23-Lg Vol Commercial A/C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
9 T1-Lg Vol Commercial Transp	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
10 30-Sm Vol Industrial	0.00%	-15.79%	0.00%	-15.79%	14.29%	6.67%	-11.11%	6.67%	-20.00%	0.00%	-5.88%	0.00%
11 31-Sm Vol Industrial A/C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
12 32-Lg Vol Industrial	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13 33-Lg Vol Industrial A/C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
14 T1-Lg Vol Industrial Transp	-9.09%	-9.09%	-9.09%	-9.09%	-9.09%	-9.09%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
15 40-Sm Vol Pub Auth	6.28%	6.02%	6.93%	3.41%	6.02%	4.64%	5.01%	3.77%	3.29%	0.92%	2.44%	0.00%
16 41-Sm Vol Pub Auth A/C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
17 42-Lg Vol Pub Auth	25.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
18 T1-Lg Vol Pub Auth Transp	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19 44-Gas Light Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20 60-Irrigation Service	-12.50%	-12.50%	-22.22%	0.00%	0.00%	-30.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

SCGD Customer Adj Percentage	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
1 10-Residential	1.86%	2.21%	1.93%	0.99%	0.34%	2.03%	1.13%	1.80%	1.72%	-0.41%	-1.84%	0.00%
2 11-Residential A/C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
3 12-CARES	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
4 13-CARES Med Life Support	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5 20-Sm Vol Commercial	-7.17%	-7.17%	-5.39%	1.12%	-4.56%	-0.73%	-0.91%	-1.81%	-0.37%	-1.27%	-3.20%	0.00%
6 21-Sm Vol Commercial A/C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
7 22-Lg Vol Commercial	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
8 23-Lg Vol Commercial A/C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
9 T1-Lg Vol Commercial Transp	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
10 30-Sm Vol Industrial	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	200.00%	200.00%	200.00%	0.00%	50.00%	0.00%
11 31-Sm Vol Industrial A/C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
12 32-Lg Vol Industrial	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13 33-Lg Vol Industrial A/C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
14 T1-Lg Vol Industrial Transp	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
15 40-Sm Vol Pub Auth	-2.94%	-1.49%	-14.29%	3.13%	-5.71%	-4.35%	-9.59%	-13.16%	-10.81%	-19.51%	-17.50%	0.00%
16 41-Sm Vol Pub Auth A/C	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
17 42-Lg Vol Pub Auth	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
18 T1-Lg Vol Pub Auth Transp	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
19 44-Gas Light Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20 60-Irrigation Service	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

Citizens Communication Company
Sales and Demand Model
Year End Customer Adjustment - Weather Adjusted Sales

NAGD Calendar Month Weather Adjusted Sales	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TY TOTAL
1 10-Residential	11,201,354	8,936,750	8,416,126	6,032,146	3,489,126	2,061,623	1,570,218	1,507,858	1,718,543	2,991,373	5,761,154	9,831,471	63,517,742
2 11-Residential A/C	696	548	557	366	230	143	196	199	151	141	159	478	3,863
3 12-CARES	158,183	115,638	109,574	76,423	45,530	28,597	21,244	20,189	24,217	39,521	82,931	142,310	864,356
4 13-CARES Med Life Support	134	109	81	46	23	15	13	13	15	51	108	141	751
5 20-Sm Vol Commercial	4,043,344	3,225,609	3,107,149	2,361,495	1,751,455	1,415,968	1,198,245	1,156,391	1,244,398	1,651,335	2,426,682	3,600,797	27,182,867
6 21-Sm Vol Commercial A/C	2,772	2,176	1,922	1,589	2,047	2,589	2,735	2,458	2,070	1,988	1,990	2,444	26,781
7 22-Lg Vol Commercial	267,907	197,656	200,422	165,116	137,610	93,726	69,398	71,038	88,342	140,402	212,623	271,965	1,916,206
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	253,883	215,064	222,971	201,281	164,651	146,742	134,145	132,869	126,916	177,578	204,585	253,659	2,234,344
10 30-Sm Vol Industrial	97,706	89,032	110,805	88,471	67,223	64,224	52,908	55,693	57,154	56,215	66,731	103,514	909,678
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	307,084	229,288	251,485	264,117	244,439	220,429	175,752	154,621	177,099	241,196	278,958	370,994	2,915,462
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	1,239,167	1,015,540	1,002,920	1,233,625	1,233,353	1,010,191	1,147,399	1,355,385	1,579,366	1,031,195	1,033,303	1,355,023	14,236,466
15 40-Sm Vol Pub Auth	965,095	784,537	720,514	462,744	261,067	170,518	122,772	92,779	103,502	211,903	492,550	848,573	5,236,555
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	221,106	111,164	133,737	101,821	57,455	32,679	23,844	25,031	34,710	72,306	117,810	172,411	1,104,074
18 T1-Lg Vol Pub Auth Transp	641,887	534,759	575,821	524,397	389,478	300,972	259,980	249,647	285,291	459,873	572,339	643,690	5,438,134
19 44-Gas Light Service	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,844	8,690	106,194
20 60-Irrigation Service	2,307	1,906	1,159	3,549	16,089	28,687	37,763	35,337	25,040	21,320	13,478	5,611	192,245
21 Total	19,411,491	15,468,643	14,864,110	11,526,052	7,868,644	5,585,970	4,825,477	4,868,374	5,475,679	7,105,260	11,274,247	17,611,772	125,885,718
22 Total Sales	17,276,554	13,703,280	13,062,397	9,566,749	6,081,161	4,128,066	3,283,953	3,130,473	3,484,106	5,436,615	9,464,020	15,359,400	103,976,773
23 Total Transportation	2,134,937	1,765,363	1,801,713	1,959,303	1,787,482	1,457,904	1,541,524	1,737,901	1,991,573	1,668,645	1,810,227	2,252,372	21,908,944

SCGD Calendar Month Weather Adjusted Sales	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TY TOTAL
1 10-Residential	543,255	390,147	317,841	267,945	132,053	83,601	82,413	85,206	89,856	120,091	219,063	421,296	2,752,766
2 11-Residential A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
3 12-CARES	123,763	87,510	70,442	52,788	26,997	20,989	19,298	20,208	21,885	31,509	54,673	94,761	624,823
4 13-CARES Med Life Support	85	76	54	45	20	16	15	14	15	27	80	86	533
5 20-Sm Vol Commercial	205,772	143,799	119,642	111,024	63,547	52,998	51,854	52,783	59,674	91,378	122,524	162,265	1,237,262
6 21-Sm Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
7 22-Lg Vol Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
10 30-Sm Vol Industrial	14,885	10,734	7,632	8,402	10,529	5,555	93	70	2,236	4,845	4,909	13,188	83,078
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
15 40-Sm Vol Pub Auth	85,800	64,404	40,386	31,172	14,406	8,633	5,300	6,182	6,330	10,965	25,621	53,775	352,975
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	0	0	0	0	0	0	0	0	0	0	0	0	0
18 T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
19 44-Gas Light Service	0	0	0	0	0	0	0	0	0	0	0	0	0
20 60-Irrigation Service	0	0	0	0	0	0	0	0	0	0	0	0	0
21 Total	973,561	696,671	555,998	471,375	247,552	171,792	158,973	164,464	179,995	258,814	426,870	745,373	5,051,437
22 Total Sales	973,561	696,671	555,998	471,375	247,552	171,792	158,973	164,464	179,995	258,814	426,870	745,373	5,051,437
23 Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0

Citizens Communication Company
Sales and Demand Model
Year End Customer Adjusted Revenue

NAGD — Total Calendar Month Weather & Annualization Adjusted Base Revenue - After YEC

NAGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TY TOTAL
1 10-Residential	5,432,406	4,349,563	4,205,280	3,155,857	2,037,434	1,401,583	1,181,748	1,163,911	1,260,605	1,757,663	3,042,101	4,839,194	33,827,344
2 11-Residential A/C	331	267	271	185	126	85	103	103	86	77	95	236	1,964
3 12-CARES	77,354	57,950	56,046	41,349	27,761	20,303	17,009	16,594	18,419	24,488	44,365	70,264	471,901
4 13-CARES Med Life Support	64	53	41	25	15	12	11	11	12	27	53	67	391
5 20-Sm Vol Commercial	1,618,406	1,288,711	1,258,785	969,921	739,261	606,736	528,000	511,368	545,409	675,077	998,431	1,451,365	11,191,468
6 21-Sm Vol Commercial A/C	1,094	865	768	640	816	919	966	874	742	716	794	968	10,162
7 22-Lg Vol Commercial	91,213	68,103	69,044	57,040	47,688	32,767	24,495	25,053	30,936	48,637	73,192	93,368	661,535
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	24,575	21,082	21,793	19,841	16,545	14,933	13,799	13,684	13,148	17,708	20,139	24,555	221,802
10 30-Sm Vol Industrial	29,106	30,954	33,981	29,690	23,559	22,436	16,235	19,586	19,572	19,742	23,389	36,060	304,310
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	94,940	71,002	77,832	81,719	75,664	68,276	54,529	48,027	54,943	74,666	86,285	114,605	902,488
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	58,604	49,363	53,614	56,352	54,215	48,377	55,131	61,907	65,064	53,381	53,413	60,716	670,137
15 40-Sm Vol Pub Auth	368,264	297,627	275,513	178,669	104,207	70,409	50,465	41,354	45,446	83,759	192,287	320,097	2,028,097
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	71,510	36,184	43,390	29,311	18,717	10,878	8,036	8,440	11,562	22,159	38,345	55,943	354,475
18 T1-Lg Vol Pub Auth Transp	45,793	38,123	40,737	36,729	27,003	20,125	17,456	17,073	19,312	32,294	40,225	45,627	380,495
19 44-Gas Light Service	3,960	3,960	3,960	3,960	3,960	3,960	3,960	3,960	3,960	3,960	3,960	3,901	47,456
20 60-Irrigation Service	592	631	400	1,146	4,943	8,851	11,687	10,941	7,767	5,138	5,176	2,185	59,458
21 Total	7,918,212	6,314,437	6,141,453	4,662,434	3,181,911	2,330,647	1,983,630	1,942,885	2,096,984	2,819,492	4,622,248	7,119,152	51,133,484
22 Total Sales	7,789,240	6,205,869	6,025,309	4,549,512	3,084,149	2,247,214	1,897,244	1,850,221	1,999,459	2,716,109	4,508,472	6,988,254	49,861,050
23 Total Transportation	128,972	108,567	116,144	112,922	97,763	83,434	86,385	92,664	97,525	103,384	113,777	130,898	1,272,434

SCGD — Total Calendar Month Weather & Annualization Adjusted Base Revenue - After YEC

SCGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TY TOTAL
1 10-Residential	373,649	264,125	217,718	188,990	114,824	95,537	76,801	81,520	84,049	101,460	164,199	278,778	2,041,649
2 11-Residential A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
3 12-CARES	80,906	59,599	50,546	40,611	23,689	21,000	19,924	20,523	21,619	28,152	43,681	64,958	475,207
4 13-CARES Med Life Support	58	53	40	34	19	16	15	15	16	24	54	59	402
5 20-Sm Vol Commercial	112,198	79,124	66,655	62,556	36,994	30,907	30,091	30,399	34,069	50,835	67,597	89,272	690,698
6 21-Sm Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
7 22-Lg Vol Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
10 30-Sm Vol Industrial	7,502	5,414	3,834	4,314	5,317	2,777	75	63	1,541	2,473	2,647	6,689	42,646
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
15 40-Sm Vol Pub Auth	44,249	33,462	21,144	16,855	8,013	4,866	3,238	3,703	3,711	6,462	13,877	28,207	187,787
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	0	0	0	0	0	0	0	0	0	0	0	0	0
18 T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
19 44-Gas Light Service	0	0	0	0	0	0	0	0	0	0	0	0	0
20 60-Irrigation Service	0	0	0	0	0	0	0	0	0	0	0	0	0
21 Total	618,562	441,776	359,937	313,359	188,855	155,103	130,145	136,222	145,003	189,405	292,056	467,963	3,438,388
22 Total Sales	618,562	441,776	359,937	313,359	188,855	155,103	130,145	136,222	145,003	189,405	292,056	467,963	3,438,388
23 Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0

Citizens Communication Company
Sales and Demand Model
Year End Customer Adjusted PGA Revenues

NAGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TY TOTAL
Total Calendar Month PGA Adjusted Revenue													
1 10-Residential	1,196,885	1,009,498	987,656	787,353	489,111	301,559	236,026	227,253	259,030	1,026,830	1,978,157	3,376,539	11,875,896
2 11-Residential A/C	74	62	65	48	32	21	29	30	23	48	55	164	652
3 12-CARES	16,900	13,062	12,858	9,974	6,381	4,182	3,192	3,042	3,649	13,565	28,474	48,874	164,151
4 13-CARES Med Life Support	14	12	10	6	3	2	2	2	2	17	37	49	157
5 20-Sm Vol Commercial	432,197	364,461	364,741	308,372	245,691	207,402	180,426	174,586	187,873	567,192	833,511	1,236,823	5,103,275
6 21-Sm Vol Commercial A/C	296	246	226	207	287	379	412	371	313	683	684	840	4,943
7 22-Lg Vol Commercial	28,639	22,335	23,530	21,564	19,307	13,731	10,451	10,727	13,340	48,228	73,036	93,420	378,307
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
10 30-Sm Vol Industrial	10,445	10,061	13,008	11,554	9,431	9,409	7,968	8,410	8,630	19,310	22,922	35,557	166,705
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	32,827	25,910	29,524	34,494	34,295	32,293	26,468	23,348	26,742	82,851	95,822	127,437	572,010
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
15 40-Sm Vol Pub Auth	103,164	88,650	84,585	60,431	36,624	24,977	18,487	14,007	15,625	72,783	169,184	291,480	979,997
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	23,636	12,562	15,701	10,302	8,061	4,788	3,591	3,780	5,241	24,837	40,468	59,223	212,188
18 T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
19 44-Gas Light Service	948	1,002	1,041	1,158	1,244	1,299	1,335	1,339	1,339	3,045	3,038	3,002	19,790
20 60-Irrigation Service	247	215	136	463	2,257	4,203	5,687	5,336	3,781	7,323	4,630	1,927	36,205
21 Total	1,846,273	1,548,074	1,533,080	1,245,926	852,725	604,243	494,075	472,228	525,587	1,866,712	3,250,017	5,275,335	19,514,277
22 Total Sales	1,846,273	1,548,074	1,533,080	1,245,926	852,725	604,243	494,075	472,228	525,587	1,866,712	3,250,017	5,275,335	19,514,277
23 Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0

SCGD	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TY TOTAL
Total Calendar Month PGA Adjusted Revenue													
1 10-Residential	(25,167)	992	304	3,539	2,094	1,101	1,065	1,097	1,159	32,045	58,467	112,498	189,193
2 11-Residential A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
3 12-CARES	(5,734)	223	67	697	428	276	249	260	282	8,408	14,592	25,304	45,053
4 13-CARES Med Life Support	(4)	0	0	1	0	0	0	0	0	7	21	23	49
5 20-Sm Vol Commercial	(9,444)	195	178	1,465	842	698	681	693	784	24,404	32,723	43,339	96,559
6 21-Sm Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
7 22-Lg Vol Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
10 30-Sm Vol Industrial	(683)	15	11	111	139	73	1	1	29	1,294	1,311	3,522	5,825
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
15 40-Sm Vol Pub Auth	(3,938)	87	60	411	191	114	70	81	83	2,928	6,843	14,363	21,293
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	0	0	0	0	0	0	0	0	0	0	0	0	0
18 T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
19 44-Gas Light Service	0	0	0	0	0	0	0	0	0	0	0	0	0
20 60-Irrigation Service	0	0	0	0	0	0	0	0	0	0	0	0	0
21 Total	(44,970)	1,512	621	6,224	3,694	2,263	2,066	2,133	2,338	69,087	113,957	199,048	357,973
22 Total Sales	(44,970)	1,512	621	6,224	3,694	2,263	2,066	2,133	2,338	69,087	113,957	199,048	357,973
23 Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0

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Citizens Communications
Northern Area Gas Division
Evaluation of Alternative Allocation Methods

Line No.	Notes	Description	Total Company	Residential	Commercial	Industrial	Public Authority	Special Gas Light Service	Irrigation
1		**Recommended Allocation Method**							
2	1	Present Revenue	70,647,761	46,342,457	17,571,492	2,615,650	3,955,253	67,246	95,664
3	2, 3	Revenue at Equalized ROR	89,938,419	61,010,582	19,711,182	3,907,810	5,148,307	77,861	82,677
4		**Increase Required**	**27.31%**	**31.65%**	**12.18%**	**49.40%**	**30.16%**	**15.79%**	**-13.58%**
5									
6		**Alternative Production Allocation Method**							
7	4	**Production - Commodity (Annual Sales)**							
8		Revenue at Equalized ROR	89,938,419	60,565,692	20,099,871	4,017,696	5,073,360	83,659	98,142
9		Increase Required	27.31%	30.69%	14.39%	53.60%	28.27%	24.41%	2.59%
10		Change from Recommended Case	0.00%	-3.03%	18.17%	8.50%	-6.28%	54.62%	-119.08%
11									
12		**Alternative Transmission and Distribution Allocation Methods**							
13	5	**Trans. & Distr. - Design Day**							
14		Revenue at Equalized ROR	89,938,420	62,030,996	19,277,533	3,315,150	5,170,036	70,627	74,077
15		Increase Required	27.31%	33.85%	9.71%	26.74%	30.71%	5.03%	-22.56%
16		Change from Recommended Case	0.00%	6.96%	-20.27%	-45.87%	1.82%	-68.15%	66.21%
17									
18	6	**Trans. & Distr. - Seaboard (50% Demand / 50% Sales)**							
19		Revenue at Equalized ROR	89,938,420	60,997,387	19,601,929	4,024,825	5,147,867	76,908	89,504
20		Increase Required	27.31%	31.62%	11.56%	53.87%	30.15%	14.37%	-6.44%
21		Change from Recommended Case	0.00%	-0.09%	-5.11%	9.06%	-0.04%	-8.98%	-52.57%
22									
23	7	**Trans. & Distr. - 60% Demand / 40% Sales**							
24		Revenue at Equalized ROR	89,938,420	60,790,666	19,666,818	4,166,682	5,143,501	78,164	92,589
25		Increase Required	27.31%	31.18%	11.92%	59.30%	30.04%	16.24%	-3.21%
26		Change from Recommended Case	0.00%	-1.50%	-2.07%	20.03%	-0.40%	2.85%	-76.33%
27									
28	8	**Trans. & Distr. - 40% Demand / 60% Sales**							
29		Revenue at Equalized ROR	89,938,420	61,204,109	19,537,042	3,882,947	5,152,251	75,652	86,419
30		Increase Required	27.31%	32.07%	11.19%	48.45%	30.26%	12.50%	-9.66%
31		Change from Recommended Case	0.00%	1.32%	-8.14%	-1.92%	0.33%	-20.81%	-28.81%

Citizens Communications
Evaluation of Alternative Allocation Methods
Explanatory Notes

Introduction:

The selection of allocation methods is subject to a great deal of discretion on the part of the cost practitioner. The choice of methods can have a material impact on the results of any class cost of service study. Therefore it is prudent to examine alternatives to understand their impact on the study's conclusions.

Capacity Alternatives:

For this study, the two most critical allocators are the allocation of production costs and the allocation of mains investment. Alternatives to each will be evaluated by tabulating the revenue requirements for the major rate classes in the Northern Arizona Division at equalized rates of return. The percentage increase resulting from each alternative will be compared.

Production Allocation:

The base case production allocation method is to mirror the FERC Modified fixed Variable method by allocating pipeline reservation charges on class design day demand and allocating commodity and variable transportation costs monthly on the basis of class monthly sales. The alternative is to allocate all production costs on the basis of annual sales, the method currently used to price gas supplies.

Mains Allocation:

The base case mains allocation method is the Proportional Responsibility method, described in the work papers. Four alternatives are presented including the Design Day and three combinations of design day with annual sales - 50/50, 60/40 and 40/60.

Notes:

1. Present total revenues including sales revenues and miscellaneous service fee revenue.
2. Class revenues at claimed rate of return comparable to those shown above.
3. Employs the base case (recommended) allocation methods - MFV for production and PR for mains.
4. Allocation of all production costs based on annual sales.
5. Mains allocated on design day allocator.
6. Mains allocated on design day allocator weighted by 50% and annual sales weighted by 50%.
7. Mains allocated on design day allocator weighted by 60% and annual sales weighted by 40%
8. Mains allocated on design day allocator weighted by 40% and annual sales weighted by 60%

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CITIZENS UTILITIES COMPANY - NORTHERN ARIZONA GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
12 MONTHS ENDED DECEMBER 31, 2001

LINE NO.	DESCRIPTION	ALLOC FACTOR	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)	COGENERATION (8)
1	DEMAND RELATED									
2										
3	PRODUCTION ALLOCATORS									
4	------------------------------------									
5	PRODUCTION DEMAND ALLOCATOR	DEMGAS								
6	DESIGN DAY DEMAND		1,012,379	682,693	233,894	24,287	71,089	298	119	0
7	COMMODITY + CAPACITY		45,368,070	28,093,782	12,708,451	1,669,019	2,766,600	46,336	83,882	0
8	COMMODITY GAS COSTS		40,020,593	24,877,564	11,133,326	1,443,667	2,456,814	39,692	69,531	0
9										
10	TRANSMISSION ALLOCATORS									
11	------------------------------------									
12	PROPORTIONAL RESPONSIBILITY	TRANS	1.000000	0.559713	0.239186	0.105452	0.094549	0.000598	0.000502	0.000000
13										
14										
15										
16										
17	DISTRIBUTION ALLOCATORS									
18	------------------------------------									
19	DISTRIBUTION ALLOCATOR	DISTR								
20	DISTRIBUTION MAINS	DISTMAIN	1.000000	0.559713	0.239186	0.105452	0.094549	0.000598	0.000502	0.000000
21	DISTRIBUTION REGULATORS	DISTREG	1.000000	0.559713	0.239186	0.105452	0.094549	0.000598	0.000502	0.000000
22										
23	DESIGN DAY		1,125,182	682,693	246,640	87,967	107,465	298	119	0
24	PERCENT		1.00000	0.60674	0.21920	0.07818	0.09551	0.00026	0.00011	0.00000
25										
26	COMMODITY		125,885,718	64,386,712	31,360,198	18,061,606	11,778,763	106,194	192,245	0
27	PERCENT		1.00000	0.51147	0.24912	0.14348	0.09357	0.00084	0.00153	0.00000
28										
29	SEABOARD (50/50)		1.00000	0.55910	0.23416	0.11083	0.09454	0.00055	0.00082	0.00000
30	60% COMMODITY 40% DEMAND		1.00000	0.54958	0.23715	0.11736	0.09434	0.00061	0.00096	0.00000
31	40% COMMODITY 60% DEMAND		1.00000	0.56863	0.23117	0.10430	0.09473	0.00050	0.00067	0.00000
32	PROPORTIONAL RESPONSIBILITY		1.00000	0.55971	0.23919	0.10545	0.09455	0.00060	0.00050	0.00000
33										
34										
35	COMMODITY RELATED									
36	------------------------------------									
37	COMMODITY ALLOCATOR	GASSALES								
38	COMMODITY GAS COSTS		40,020,593	24,877,564	11,133,326	1,443,667	2,456,814	39,692	69,531	0
39	COMMODITY + CAPACITY		45,368,070	28,093,782	12,708,451	1,669,019	2,766,600	46,336	83,882	0
40	ANNUAL FIRM THERM THROUGHPUT		125,885,718	64,386,712	31,360,198	18,061,606	11,778,763	106,194	192,245	0
41	CARES		125,020,611	63,521,605	31,360,198	18,061,606	11,778,763	106,194	192,245	0
42										
43										

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CITIZENS UTILITIES COMPANY - NORTHERN ARIZONA GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
12 MONTHS ENDED DECEMBER 31, 2001

LINE NO.	DESCRIPTION	ALLOC FACTOR	COMMERCIAL SM. VOL. (9)	COMMERCIAL LG. VOL. (10)	INDUSTRIAL SM. VOL. (11)	INDUSTRIAL LG. VOL. (12)	PUBLIC AUTHORITY SM. VOL. (13)	PUBLIC AUTHORITY LG. VOL. (14)
1	DEMAND RELATED							
2								
3	PRODUCTION ALLOCATORS							
4	--							
5	PRODUCTION DEMAND ALLOCATOR	DEMGAS						
6	DESIGN DAY DEMAND		218,289	15,604	5,849	18,438	59,303	11,786
7	COMMODITY + CAPACITY		11,872,355	836,096	396,919	1,272,100	2,284,860	481,739
8	COMMODITY GAS COSTS		10,401,568	731,758	343,807	1,099,860	2,030,446	426,368
9								
10	TRANSMISSION ALLOCATORS							
11	--							
12	PROPORTIONAL RESPONSIBILITY	TRANS	0.209686	0.029500	0.006100	0.099351	0.047006	0.047543
13								
14								
15								
16								
17	DISTRIBUTION ALLOCATORS							
18	--							
19	DISTRIBUTION ALLOCATOR	DISTR						
20	DISTRIBUTION MAINS	DISTMAIN	0.209686	0.029500	0.006100	0.099351	0.047006	0.047543
21	DISTRIBUTION REGULATORS	DISTREG	0.209686	0.029500	0.006100	0.099351	0.047006	0.047543
22								
23	DESIGN DAY		218,289	28,351	5,849	82,118	59,303	48,162
24	PERCENT		0.19400	0.02520	0.00520	0.07298	0.05271	0.04280
25								
26	COMMODITY		27,209,648	4,150,550	909,678	17,151,929	5,236,555	6,542,207
27	PERCENT		0.21615	0.03297	0.00723	0.13625	0.04160	0.05197
28								
29	SEABOARD (50/50)		0.20507	0.02908	0.00621	0.10462	0.04715	0.04739
30	60% COMMODITY 40% DEMAND		0.20729	0.02986	0.00641	0.11094	0.04604	0.04830
31	40% COMMODITY 60% DEMAND		0.20286	0.02831	0.00601	0.09829	0.04826	0.04647
32	PROPORTIONAL RESPONSIBILITY		0.20969	0.02950	0.00610	0.09935	0.04701	0.04754
33								
34								
35	COMMODITY RELATED							
36	--							
37	COMMODITY ALLOCATOR	GASSALES						
38	COMMODITY GAS COSTS		10,401,568	731,758	343,807	1,099,860	2,030,446	426,368
39	COMMODITY + CAPACITY		11,872,355	836,096	396,919	1,272,100	2,284,860	481,739
40	ANNUAL FIRM THERM THROUGHPUT		27,209,648	4,150,550	909,678	17,151,929	5,236,555	6,542,207
41	CARES		27,209,648	4,150,550	909,678	17,151,929	5,236,555	6,542,207
42								
43								

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CITIZENS UTILITIES COMPANY - NORTHERN ARIZONA GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
12 MONTHS ENDED DECEMBER 31, 2001

PRESENT RATE SCHEDULE DETAIL

LINE NO.	DESCRIPTION	ALLOC FACTOR	RESIDENTIAL SERVICE (15)	RESIDENTIAL AIR COND. (16)	CARES (17)	CARES MED. LIFE SUPP. (18)	SM. VOL. (19)	SM. VOL. AIR COND. (20)	LG. VOL. (21)	LG. VOL. AIR COND. (22)	TRANSPORTATION (23)
			RESIDENTIAL				COMMERCIAL				
1	DEMAND RELATED										
2											
3	PRODUCTION ALLOCATORS										
4											
5	PRODUCTION DEMAND ALLOCATOR	DEMGAS									
6	DESIGN DAY DEMAND		673,279	38	9,367	9	218,183	106	15,604	0	0
7	COMMODITY + CAPACITY		27,714,625	1,686	377,144	328	11,860,670	11,685	836,096	0	0
8	COMMODITY GAS COSTS		24,541,380	1,484	334,408	292	10,391,536	10,032	731,758	0	0
9											
10	TRANSMISSION ALLOCATORS										
11											
12	PROPORTIONAL RESPONSIBILITY	TRANS	0.552053	0.000032	0.007621	0.000007	0.209529	0.000157	0.014516	0.000000	0.014984
13											
14											
15											
16											
17	DISTRIBUTION ALLOCATORS										
18											
19	DISTRIBUTION ALLOCATOR	DISTR									
20	DISTRIBUTION MAINS	DISTMAIN	0.552053	0.000032	0.007621	0.000007	0.209529	0.000157	0.014516	0.000000	0.014984
21	DISTRIBUTION REGULATORS	DISTREG	0.552053	0.000032	0.007621	0.000007	0.209529	0.000157	0.014516	0.000000	0.014984
22											
23	DESIGN DAY		673,279	38	9,367	9	218,183	106	15,604	0	12,747
24	PERCENT		0.59837	0.00003	0.00832	0.00001	0.19391	0.00009	0.01387	0.00000	0.01133
25											
26	COMMODITY		63,517,742	3,863	864,356	751	27,182,867	26,781	1,916,206	0	2,234,344
27	PERCENT		0.50457	0.00003	0.00687	0.00001	0.21593	0.00021	0.01522	0.00000	0.01775
28											
29	SEABOARD (50/50)		0.55147	0.00003	0.00760	0.00001	0.20492	0.00015	0.01454	0.00000	0.01454
30	60% COMMODITY 40% DEMAND		0.54209	0.00003	0.00745	0.00001	0.20712	0.00017	0.01468	0.00000	0.01518
31	40% COMMODITY 60% DEMAND		0.56085	0.00003	0.00774	0.00001	0.20272	0.00014	0.01441	0.00000	0.01390
32	PROPORTIONAL RESPONSIBILITY		0.55205	0.00003	0.00762	0.00001	0.20953	0.00016	0.01452	0.00000	0.01498
33											
34											
35	COMMODITY RELATED										
36											
37	COMMODITY ALLOCATOR	GASSALES									
38	COMMODITY GAS COSTS		24,541,380	1,484	334,408	292	10,391,536	10,032	731,758	0	0
39	COMMODITY + CAPACITY		27,714,625	1,686	377,144	328	11,860,670	11,685	836,096	0	0
40	ANNUAL FIRM THERM THROUGHPUT		63,517,742	3,863	864,356	751	27,182,867	26,781	1,916,206	0	2,234,344
41	CARES		63,517,742	3,863	0	0	27,182,867	26,781	1,916,206	0	2,234,344
42											
43											

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CITIZENS UTILITIES COMPANY - NORTHERN ARIZONA GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
12 MONTHS ENDED DECEMBER 31, 2001

LINE NO.	DESCRIPTION	ALLOC FACTOR	INDUSTRIAL SM. VOL. (24)	INDUSTRIAL SM. VOL. AIR COND. (25)	INDUSTRIAL LG. VOL. (26)	INDUSTRIAL LG. VOL. AIR COND. (27)	INDUSTRIAL TRANSPORTATION (28)	PUBLIC AUTHORITY SM. VOL. (29)	PUBLIC AUTHORITY SM. VOL. AIR COND. (30)	PUBLIC AUTHORITY LG. VOL. (31)	PUBLIC AUTHORITY LG. VOL. AIR COND. (32)	PUBLIC AUTHORITY TRANSPORTATION (33)
1	DEMAND RELATED											
2												
3	PRODUCTION ALLOCATORS											
4												
5	PRODUCTION DEMAND ALLOCATOR	DEMGAS										
6	DESIGN DAY DEMAND		5,849	0	18,438	0	0	59,303	0	11,786	0	0
7	COMMODITY + CAPACITY		396,919	0	1,272,100	0	0	2,284,860	0	481,739	0	0
8	COMMODITY GAS COSTS		343,807	0	1,099,860	0	0	2,030,446	0	426,368	0	0
9												
10	TRANSMISSION ALLOCATORS											
11												
12	PROPORTIONAL RESPONSIBILITY	TRANS	0.006100	0.000000	0.019059	0.000000	0.080293	0.047006	0.000000	0.009733	0.000000	0.037810
13												
14												
15												
16												
17	DISTRIBUTION ALLOCATORS											
18												
19	DISTRIBUTION ALLOCATOR	DISTR										
20	DISTRIBUTION MAINS	DISTMAIN	0.006100	0.000000	0.019059	0.000000	0.080293	0.047006	0.000000	0.009733	0.000000	0.037810
21	DISTRIBUTION REGULATORS	DISTREG	0.006100	0.000000	0.019059	0.000000	0.080293	0.047006	0.000000	0.009733	0.000000	0.037810
22												
23	DESIGN DAY		5,849	0	18,438	0	63,680	59,303	0	11,786	0	36,376
24	PERCENT		0.00520	0.00000	0.01639	0.00000	0.05660	0.05271	0.00000	0.01047	0.00000	0.03233
25												
26	COMMODITY		909,678	0	2,915,462	0	14,236,466	5,236,555	0	1,104,074	0	5,438,134
27	PERCENT		0.00723	0.00000	0.02316	0.00000	0.11309	0.04160	0.00000	0.00877	0.00000	0.04320
28												
29	SEABOARD (50/50)		0.00621	0.00000	0.01977	0.00000	0.08484	0.04715	0.00000	0.00962	0.00000	0.03776
30	60% COMMODITY 40% DEMAND		0.00641	0.00000	0.02045	0.00000	0.09049	0.04604	0.00000	0.00945	0.00000	0.03885
31	40% COMMODITY 60% DEMAND		0.00601	0.00000	0.01910	0.00000	0.07919	0.04826	0.00000	0.00979	0.00000	0.03668
32	PROPORTIONAL RESPONSIBILITY		0.00610	0.00000	0.01906	0.00000	0.08029	0.04701	0.00000	0.00973	0.00000	0.03781
33												
34												
35	COMMODITY RELATED											
36												
37	COMMODITY ALLOCATOR	GASSALES										
38	COMMODITY GAS COSTS		343,807	0	1,099,860	0	0	2,030,446	0	426,368	0	0
39	COMMODITY + CAPACITY		396,919	0	1,272,100	0	0	2,284,860	0	481,739	0	0
40	ANNUAL FIRM THERM THROUGHPUT		909,678	0	2,915,462	0	14,236,466	5,236,555	0	1,104,074	0	5,438,134
41	CARES		909,678	0	2,915,462	0	14,236,466	5,236,555	0	1,104,074	0	5,438,134
42												
43												

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CITIZENS UTILITIES COMPANY - NORTHERN ARIZON
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACT(
12 MONTHS ENDED DECEMBER 31, 20

LINE NO.	DESCRIPTION	ALLOC FACTOR	SPECIAL GAS LIGHT SERVICE (34)	IRRIGATION (35)	COGENERATION (36)
1	DEMAND RELATED				
2					
3	PRODUCTION ALLOCATORS				
4	--				
5	PRODUCTION DEMAND ALLOCATOR	DEMGAS			
6	DESIGN DAY DEMAND		298	119	0
7	COMMODITY + CAPACITY		46,336	83,882	0
8	COMMODITY GAS COSTS		39,692	69,531	0
9					
10	TRANSMISSION ALLOCATORS				
11	--				
12	PROPORTIONAL RESPONSIBILITY	TRANS	0.000598	0.000502	0.000000
13					
14					
15					
16					
17	DISTRIBUTION ALLOCATORS				
18	--				
19	DISTRIBUTION ALLOCATOR	DISTR			
20	DISTRIBUTION MAINS	DISTMAIN	0.000598	0.000502	0.000000
21	DISTRIBUTION REGULATORS	DISTREG	0.000598	0.000502	0.000000
22					
23	DESIGN DAY		298	119	0
24	PERCENT		0.00026	0.00011	0.00000
25					
26	COMMODITY		106,194	192,245	0
27	PERCENT		0.00084	0.00153	0.00000
28					
29	SEABOARD (50/50)		0.00055	0.00082	0.00000
30	60% COMMODITY 40% DEMAND		0.00061	0.00096	0.00000
31	40% COMMODITY 60% DEMAND		0.00050	0.00067	0.00000
32	PROPORTIONAL RESPONSIBILITY		0.00060	0.00050	0.00000
33					
34					
35	COMMODITY RELATED				
36	--				
37	COMMODITY ALLOCATOR	GASSALES			
38	COMMODITY GAS COSTS		39,692	69,531	0
39	COMMODITY + CAPACITY		46,336	83,882	0
40	ANNUAL FIRM THERM THROUGHPUT		106,194	192,245	0
41	CARES		106,194	192,245	0
42					
43					

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CITIZENS UTILITIES COMPANY - NORTHERN ARIZONA GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
12 MONTHS ENDED DECEMBER 31, 2001

LINE NO.	DESCRIPTION	ALLOC FACTOR	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)	COGENERATION (8)
44	CUSTOMER RELATED									
45	------------------------------									
46	YEAR END NUMBER OF CUSTOMERS	CUST10	112,971	102,494	9,543	32	891	4	7	0
47	NO OF LIGHTING INSTALLATIONS									
48										
49	ACCT 380-SERVICES									
50	WEIGHTING FACTOR									
51	SERVICES ALLOCATION FACTOR	CUST380	47,288,874	42,861,524	4,011,611	29,279	383,533	0	2,927	0
52										
53	ACCT 381-METERS									
55	METER ALLOCATION FACTOR	CUST381	13,099,197	12,272,632	754,969	1,269	69,772	0	555	0
56										
57	ACCT 382-METER INSTALLATIONS									
58										
59	METER INSTALLATION ALLOCATION FACTOR	CUST382	13,099,197	12,272,632	754,969	1,269	69,772	0	555	0
60										
61	ACCT 383-HOUSE REGULATORS									
63	HOUSE REGULATOR ALLOCATION FACTOR	CUST383	13,099,197	12,272,632	754,969	1,269	69,772	0	555	0
64										
65	ACCT 384-HOUSE REG. INSTALLATION									
67	HOUSE REG. INSTALLATION ALLOCATION FACTOR	CUST384	13,099,197	12,272,632	754,969	1,269	69,772	0	555	0
68										
69	ACCT 385-INDUSTRIAL REG EQUIP									
71	INDUSTRIAL REG EQUIP ALLOCATION FACTOR	CUST385	2,502,551	0	2,159,560	91,848	249,641	0	1,502	0
72										
73	CUSTOMER DEPOSITS									
74	REPORTED CLASS TOTAL			1,005,010	269,592	19,070	200			
75	TIMES THERM PERCENTAGE									
76	CUSTOMER DEPOSITS ALLOCATION FACTOR	CUSTDEP	1,293,871	1,005,010	267,824	19,070	200	0	1,768	0
77										
78	CUSTOMER ADVANCES (currently not used)	CUSTADV	112,971	102,494	9,543	32	891	4	7	0
79	CONTR IN AID OF CONSTR-SERVICES (currently not used)	CONTSERV	112,971	102,494	9,543	32	891	4	7	0
80	CONTR IN AID OF CONSTR-MAINS (currently not used)	CONTMAIN	112,971	102,494	9,543	32	891	4	7	0
81	487-FORFEITED DISCOUNTS (currently not used)	CUST487A	324,971	170,991	83,774	37,984	31,919	0	303	0
82	487-MISCELLANEOUS SERVICE REV	CUST487B	484,591	458,820	25,131	0	640	0	0	0
83										
84	ACCT 902-METER READ EXP									
85	WEIGHTING FACTOR									
86	METER READING EXPENSE ALLOCATON FACTOR	CUST902	68,688	62,349	5,502	216	617	0	4	0

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CITIZENS UTILITIES COMPANY - NORTHERN ARIZONA GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
12 MONTHS ENDED DECEMBER 31, 2001

LINE NO.	DESCRIPTION	ALLOC FACTOR	COMMERCIAL SM. VOL. (9)	COMMERCIAL LG. VOL. (10)	INDUSTRIAL SM. VOL. (11)	INDUSTRIAL LG. VOL. (12)	PUBLIC AUTHORITY SM. VOL. (13)	PUBLIC AUTHORITY LG. VOL. (14)
44	CUSTOMER RELATED							
45	------------------------------							
46	YEAR END NUMBER OF CUSTOMERS	CUST10	9,522	21	16	16	880	11
47	NO OF LIGHTING INSTALLATIONS							
48								
49	ACCT 380-SERVICES							
50	WEIGHTING FACTOR							
51	SERVICES ALLOCATION FACTOR	CUST380	3,981,964	29,647	6,691	22,588	368,003	15,529
52								
53	ACCT 381-METERS							
55	METER ALLOCATION FACTOR	CUST381	754,969	0	1,269	0	69,772	0
56								
57	ACCT 382-METER INSTALLATIONS							
58								
59	METER INSTALLATION ALLOCATION FACTOR	CUST382	754,969	0	1,269	0	69,772	0
60								
61	ACCT 383-HOUSE REGULATORS							
63	HOUSE REGULATOR ALLOCATION FACTOR	CUST383	754,969	0	1,269	0	69,772	0
64								
65	ACCT 384-HOUSE REG. INSTALLATION							
67	HOUSE REG. INSTALLATION ALLOCATION FACTOR	CUST384	754,969	0	1,269	0	69,772	0
68								
69	ACCT 385-INDUSTRIAL REG EQUIP							
71	INDUSTRIAL REG EQUIP ALLOCATION FACTOR	CUST385	2,043,517	116,043	3,434	88,414	188,857	60,785
72								
73	CUSTOMER DEPOSITS							
74	REPORTED CLASS TOTAL							
75	TIMES THERM PERCENTAGE							
76	CUSTOMER DEPOSITS ALLOCATION FACTOR	CUSTDEP	250,203	17,620	4,535	14,535	165	35
77								
78	CUSTOMER ADVANCES (currently not used)	CUSTADV	9,522	21	16	16	880	11
79	CONTR IN AID OF CONSTR-SERVICES (currently not used)	CONTSERV	9,522	21	16	16	880	11
80	CONTR IN AID OF CONSTR-MAINS (currently not used)	CONTMAIN	9,522	21	16	16	880	11
81	487-FORFEITED DISCOUNTS (currently not used)	CUST487A	71,085	12,689	1,769	36,214	10,937	20,982
82	487-MISCELLANEOUS SERVICE REV	CUST487B	25,131	0	0	0	640	0
83								
84	ACCT 902-METER READ EXP							
85	WEIGHTING FACTOR							
86	METER READING EXPENSE ALLOCATON FACTOR	CUST902	5,308	194	9	207	491	126

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CITIZENS UTILITIES COMPANY - NORTHERN ARIZONA GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
12 MONTHS ENDED DECEMBER 31, 2001

PRESENT RATE SCHEDULE DETAIL

LINE NO.	DESCRIPTION	ALLOC FACTOR	RESIDENTIAL: RESIDENTIAL SERVICE (15)	RESIDENTIAL: RESIDENTIAL AIR COND. (16)	RESIDENTIAL: CARES (17)	RESIDENTIAL: CARES MED. LIFE SUPP. (18)	COMMERCIAL: SM. VOL. (19)	COMMERCIAL: SM. VOL. AIR COND. (20)	COMMERCIAL: LG. VOL. (21)	COMMERCIAL: LG. VOL. AIR COND. (22)	TRANSPORTATION (23)
44	CUSTOMER RELATED										
45											
46	YEAR END NUMBER OF CUSTOMERS	CUST10	100,938	5	1,550	1	9,518	4	12	0	9
47	NO OF LIGHTING INSTALLATIONS										
48											
49	ACCT 380-SERVICES										
50	WEIGHTING FACTOR		NA	NA	NA	NA	NA	NA	NA	NA	NA
51	SERVICES ALLOCATION FACTOR	CUST380	42,210,827	2,091	648,188	418	3,980,291	1,673	16,941	0	12,706
52											
53	ACCT 381-METERS										
55	METER ALLOCATION FACTOR	CUST381	12,086,316	599	185,597	120	754,652	317	0	0	0
56											
57	ACCT 382-METER INSTALLATIONS										
58											
59	METER INSTALLATION ALLOCATION FACTOR	CUST382	12,086,316	599	185,597	120	754,652	317	0	0	0
60											
61	ACCT 383-HOUSE REGULATORS										
63	HOUSE REGULATOR ALLOCATION FACTOR	CUST383	12,086,316	599	185,597	120	754,652	317	0	0	0
64											
65	ACCT 384-HOUSE REG. INSTALLATION										
67	HOUSE REG. INSTALLATION ALLOCATION FACTOR	CUST384	12,086,316	599	185,597	120	754,652	317	0	0	0
68											
69	ACCT 385-INDUSTRIAL REG EQUIP										
71	INDUSTRIAL REG EQUIP ALLOCATION FACTOR	CUST385	0	0	0	0	2,042,658	858	66,310	0	49,733
72											
73	CUSTOMER DEPOSITS										
74	REPORTED CLASS TOTAL										
75	TIMES THERM PERCENTAGE		98.65%	0.01%	1.34%	0.00%	92.72%	0.09%	6.54%	0.00%	
76	CUSTOMER DEPOSITS ALLOCATION FACTOR	CUSTDEP	991,446	60	13,492	12	249,957	246	17,620	0	0
77											
78	CUSTOMER ADVANCES (currently not used)	CUSTADV	100,938	5	1,550	1	9,518	4	12	0	9
79	CONTR IN AID OF CONSTR-SERVICES (currently not used)	CONTSERV	100,938	5	1,550	1	9,518	4	12	0	9
80	CONTR IN AID OF CONSTR-MAINS (currently not used)	CONTMAIN	100,938	5	1,550	1	9,518	4	12	0	9
81	487-FORFEITED DISCOUNTS (currently not used)	CUST487A	167,546	6	3,440	0	71,038	47	1,913	0	10,776
82	487-MISCELLANEOUS SERVICE REV	CUST487B	449,930	10	8,880	0	25,131	0	0	0	0
83											
84	ACCT 902-METER READ EXP										
85	WEIGHTING FACTOR		0.608	0.608	0.608	0.608	0.557	0.557	1.200	1.200	20.000
86	METER READING EXPENSE ALLOCATON FACTOR	CUST902	61,403	3	943	1	5,305	2	14	0	180

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CITIZENS UTILITIES COMPANY - NORTHERN ARIZONA GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
12 MONTHS ENDED DECEMBER 31, 2001

LINE NO.	DESCRIPTION	ALLOC FACTOR	INDUSTRIAL SM. VOL. (24)	SM. VOL. AIR COND. (25)	LG. VOL. (26)	LG. VOL. AIR COND. (27)	TRANSPORTATION (28)	PUBLIC AUTHORITY SM. VOL. (29)	SM. VOL. AIR COND. (30)	LG. VOL. (31)	LG. VOL. AIR COND. (32)	TRANSPORTATION (33)
44	CUSTOMER RELATED											
45												
46	YEAR END NUMBER OF CUSTOMERS	CUST10	16	0	6	0	10	880	0	5	0	6
47	NO OF LIGHTING INSTALLATIONS											
48												
49	ACCT 380-SERVICES											
50	WEIGHTING FACTOR		NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
51	SERVICES ALLOCATION FACTOR	CUST380	6,691	0	8,471	0	14,118	368,003	0	7,059	0	8,471
52												
53	ACCT 381-METERS											
55	METER ALLOCATION FACTOR	CUST381	1,269	0	0	0	0	69,772	0	0	0	0
56												
57	ACCT 382-METER INSTALLATIONS											
58												
59	METER INSTALLATION ALLOCATION FACTOR	CUST382	1,269	0	0	0	0	69,772	0	0	0	0
60												
61	ACCT 383-HOUSE REGULATORS											
63	HOUSE REGULATOR ALLOCATION FACTOR	CUST383	1,269	0	0	0	0	69,772	0	0	0	0
64												
65	ACCT 384-HOUSE REG. INSTALLATION											
67	HOUSE REG. INSTALLATION ALLOCATION FACTOR	CUST384	1,269	0	0	0	0	69,772	0	0	0	0
68												
69	ACCT 385-INDUSTRIAL REG EQUIP											
71	INDUSTRIAL REG EQUIP ALLOCATION FACTOR	CUST385	3,434	0	33,155	0	55,259	188,857	0	27,629	0	33,155
72												
73	CUSTOMER DEPOSITS											
74	REPORTED CLASS TOTAL											
75	TIMES THERM PERCENTAGE		23.78%	0.00%	76.22%	0.00%		82.59%	0.00%	17.41%	0.00%	
76	CUSTOMER DEPOSITS ALLOCATION FACTOR	CUSTDEP	4,535	0	14,535	0	0	165	0	35	0	0
77												
78	CUSTOMER ADVANCES (currently not used)	CUSTADV	16	0	6	0	10	880	0	5	0	6
79	CONTR IN AID OF CONSTR-SERVICES (currently not used)	CONTSERV	16	0	6	0	10	880	0	5	0	6
80	CONTR IN AID OF CONSTR-MAINS (currently not used)	CONTMAIN	16	0	6	0	10	880	0	5	0	6
81	487-FORFEITED DISCOUNTS (currently not used)	CUST487A	1,769	0	3,657	0	32,557	10,937	0	2,496	0	18,486
82	487-MISCELLANEOUS SERVICE REV	CUST487B	0	0	0	0	0	640	0	0	0	0
83												
84	ACCT 902-METER READ EXP											
85	WEIGHTING FACTOR		0.557	0.557	1.200	1.200	20.000	0.557	0.557	1.200	1.200	20.000
86	METER READING EXPENSE ALLOCATON FACTOR	CUST902	9	0	7	0	200	491	0	6	0	120

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CITIZENS UTILITIES COMPANY - NORTHERN ARIZON
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACT(
12 MONTHS ENDED DECEMBER 31, 20

LINE NO.	DESCRIPTION	ALLOC FACTOR	SPECIAL GAS LIGHT SERVICE (34)	IRRIGATION (35)	COGENERATION (36)
44	CUSTOMER RELATED				
45	------------------------------------				
46	YEAR END NUMBER OF CUSTOMERS	CUST10	4	7	0
47	NO OF LIGHTING INSTALLATIONS		424		
48					
49	ACCT 380-SERVICES				
50	WEIGHTING FACTOR		NA	NA	NA
51	SERVICES ALLOCATION FACTOR	CUST380	0	2,927	0
52					
53	ACCT 381-METERS				
55	METER ALLOCATION FACTOR	CUST381	0	555	0
56					
57	ACCT 382-METER INSTALLATIONS				
58					
59	METER INSTALLATION ALLOCATION FACTOR	CUST382	0	555	0
60					
61	ACCT 383-HOUSE REGULATORS				
63	HOUSE REGULATOR ALLOCATION FACTOR	CUST383	0	555	0
64					
65	ACCT 384-HOUSE REG. INSTALLATION				
67	HOUSE REG. INSTALLATION ALLOCATION FACTOR	CUST384	0	555	0
68					
69	ACCT 385-INDUSTRIAL REG EQUIP				
71	INDUSTRIAL REG EQUIP ALLOCATION FACTOR	CUST385	0	1,502	0
72					
73	CUSTOMER DEPOSITS				
74	REPORTED CLASS TOTAL				
75	TIMES THERM PERCENTAGE			0.66%	
76	CUSTOMER DEPOSITS ALLOCATION FACTOR	CUSTDEP	0	1,768	0
77					
78	CUSTOMER ADVANCES (currently not used)	CUSTADV	4	7	0
79	CONTR IN AID OF CONSTR-SERVICES (currently not used)	CONTSERV	4	7	0
80	CONTR IN AID OF CONSTR-MAINS (currently not used)	CONTMAIN	4	7	0
81	487-FORFEITED DISCOUNTS (currently not used)	CUST487A	0	303	0
82	487-MISCELLANEOUS SERVICE REV	CUST487B	0	0	0
83					
84	ACCT 902-METER READ EXP				
85	WEIGHTING FACTOR		0.000	0.557	0.000
86	METER READING EXPENSE ALLOCATON FACTOR	CUST902	0	4	0

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CITIZENS UTILITIES COMPANY - NORTHERN ARIZONA GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
12 MONTHS ENDED DECEMBER 31, 2001

LINE NO.	DESCRIPTION	ALLOC FACTOR	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)	COGENERATION (8)
87										
88	ACCT 903-CUST RECORDS & COLL									
89	DIRECT ASSIGNMENT TO TRANSMISSION	3,500								
90	CUSTOMER PERCENTAGE									
91	ASSIGNMENT SUBTOTAL		3,500	0	1,260	1,400	840	0	0	0
92	BALANCE OF BILLING COSTS	3,686,700								
93	CUSTOMER PERCENTAGE									
94	ASSIGNMENT SUBTOTAL		3,686,700	3,333,139	310,049	715	28,780	13,789	228	0
95	REPORTED CLASS ASSIGNMENT OF COLLECTION COSTS									
96	RESIDENTIAL	134,145								
97	CUSTOMER PERCENTAGE									
98	ASSIGNMENT SUBTOTAL		134,145	134,145	0	0	0	0	0	0
99	SMALL VOLUME	28,506								
100	CUSTOMER PERCENTAGE									
101	ASSIGNMENT SUBTOTAL		28,506	0	25,019	42	2,312	1,114	18	0
102	LARGE VOLUME	5,030								
103	CUSTOMER PERCENTAGE									
104	ASSIGNMENT SUBTOTAL		5,030	0	2,625	1,312	1,094	0	0	0
105	ACCT 903-CUST RECORD & COLL ALLOC FACT(	CUST903	3,857,881	3,467,284	338,952	3,470	33,026	14,903	246	0
106										
107	ACCT 912-DEMO & SELLING									
108	ACCT 913-ADVERTISING EXPENSES									
109	WEIGHTING FACTOR									
110	ACCT 912 - ALLOCATION FACTOR	CDA912	117,555	102,494	12,350	1,031	1,666	5	8	0
111	ACCT 913 - ALLOCATION FACTOR	CDA913	117,555	102,494	12,350	1,031	1,666	5	8	0
112										
113										
114	REVENUE RELATED									
115	--									
116	PRESENT ADJUSTED BASE REVENUE		51,133,484	34,301,601	12,084,967	1,876,935	2,763,067	47,456	59,458	0
117	PRESENT ADJUSTED PGA REVENUE		19,514,277	12,040,856	5,486,525	738,715	1,192,186	19,790	36,205	0
118	TOTAL PRESENT REVENUE		70,647,761	46,342,457	17,571,492	2,615,650	3,955,253	67,246	95,664	0
119										

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CITIZENS UTILITIES COMPANY - NORTHERN ARIZONA GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
12 MONTHS ENDED DECEMBER 31, 2001

LINE NO.	DESCRIPTION	ALLOC FACTOR	COMMERCIAL SM. VOL. (9)	COMMERCIAL LG. VOL. (10)	INDUSTRIAL SM. VOL. (11)	INDUSTRIAL LG. VOL. (12)	PUBLIC AUTHORITY SM. VOL. (13)	PUBLIC AUTHORITY LG. VOL. (14)
87								
88	ACCT 903-CUST RECORDS & COLL							
89	DIRECT ASSIGNMENT TO TRANSMISSION	3,500						
90	CUSTOMER PERCENTAGE							
91	ASSIGNMENT SUBTOTAL		0	1,260	0	1,400	0	840
92	BALANCE OF BILLING COSTS	3,686,700						
93	CUSTOMER PERCENTAGE							
94	ASSIGNMENT SUBTOTAL		309,659	390	520	195	28,618	163
95	REPORTED CLASS ASSIGNMENT OF COLLECTION COSTS							
96	RESIDENTIAL	134,145						
97	CUSTOMER PERCENTAGE							
98	ASSIGNMENT SUBTOTAL		0	0	0	0	0	0
99	SMALL VOLUME	28,506						
100	CUSTOMER PERCENTAGE							
101	ASSIGNMENT SUBTOTAL		25,019	0	42	0	2,312	0
102	LARGE VOLUME	5,030						
103	CUSTOMER PERCENTAGE							
104	ASSIGNMENT SUBTOTAL		0	2,625	0	1,312	0	1,094
105	ACCT 903-CUST RECORD & COLL ALLOC FACT(	CUST903	334,678	4,275	562	2,907	30,930	2,096
106								
107	ACCT 912-DEMO & SELLING							
108	ACCT 913-ADVERTISING EXPENSES							
109	WEIGHTING FACTOR							
110	ACCT 912 - ALLOCATION FACTOR	CDA912	11,426	924	19	1,012	1,056	610
111	ACCT 913 - ALLOCATION FACTOR	CDA913	11,426	924	19	1,012	1,056	610
112								
113								
114	REVENUE RELATED							
115	--							
116	PRESENT ADJUSTED BASE REVENUE		11,201,630	883,337	304,310	1,572,625	2,028,097	734,971
117	PRESENT ADJUSTED PGA REVENUE		5,108,218	378,307	166,705	572,010	979,997	212,188
118	TOTAL PRESENT REVENUE		16,309,848	1,261,644	471,015	2,144,635	3,008,094	947,159
119								

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CITIZENS UTILITIES COMPANY - NORTHERN ARIZONA GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
12 MONTHS ENDED DECEMBER 31, 2001

PRESENT RATE SCHEDULE DETAIL

LINE NO.	DESCRIPTION	ALLOC FACTOR	RESIDENTIAL: RESIDENTIAL SERVICE (15)	RESIDENTIAL: RESIDENTIAL AIR COND. (16)	RESIDENTIAL: CARES (17)	RESIDENTIAL: CARES MED. LIFE SUPP. (18)	COMMERCIAL: SM. VOL. (19)	COMMERCIAL: SM. VOL. AIR COND. (20)	COMMERCIAL: LG. VOL. (21)	COMMERCIAL: LG. VOL. AIR COND. (22)	TRANSPORTATION (23)
87											
88	ACCT 903-CUST RECORDS & COLL										
89	DIRECT ASSIGNMENT TO TRANSMISSION	3,500									
90	CUSTOMER PERCENTAGE										36.00%
91	ASSIGNMENT SUBTOTAL										1,260
92	BALANCE OF BILLING COSTS	3,686,700									
93	CUSTOMER PERCENTAGE		89.04%	0.00%	1.37%	0.00%	8.40%	0.00%	0.01%	0.00%	
94	ASSIGNMENT SUBTOTAL		3,282,537	163	50,407	33	309,529	130	390	0	
95	REPORTED CLASS ASSIGNMENT OF COLLECTION COSTS										
96	RESIDENTIAL	134,145									
97	CUSTOMER PERCENTAGE		98.48%	0.00%	1.51%	0.00%					
98	ASSIGNMENT SUBTOTAL		132,108	7	2,029	1					
99	SMALL VOLUME	28,506									
100	CUSTOMER PERCENTAGE						87.73%	0.04%			
101	ASSIGNMENT SUBTOTAL						25,009	11			
102	LARGE VOLUME	5,030									
103	CUSTOMER PERCENTAGE								52.17%	0.00%	
104	ASSIGNMENT SUBTOTAL								2,625	0	
105	ACCT 903-CUST RECORD & COLL ALLOC FACT(	CUST903	3,414,646	169	52,435	34	334,537	141	3,015	0	1,260
106											
107	ACCT 912-DEMO & SELLING										
108	ACCT 913-ADVERTISING EXPENSES										
109	WEIGHTING FACTOR		1.000	1.000	1.000	1.000	1.200	1.200	2.000	2.000	100.000
110	ACCT 912 - ALLOCATION FACTOR	CDA912	100,938	5	1,550	1	11,422	5	24	0	900
111	ACCT 913 - ALLOCATION FACTOR	CDA913	100,938	5	1,550	1	11,422	5	24	0	900
112											
113											
114	REVENUE RELATED										
115	--										
116	PRESENT ADJUSTED BASE REVENUE		33,827,344	1,964	471,901	391	11,191,468	10,162	661,535	0	221,802
117	PRESENT ADJUSTED PGA REVENUE		11,875,896	652	164,151	157	5,103,275	4,943	378,307	0	0
118	TOTAL PRESENT REVENUE		45,703,240	2,616	636,053	548	16,294,743	15,105	1,039,842	0	221,802
119											

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CITIZENS UTILITIES COMPANY - NORTHERN ARIZONA GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
12 MONTHS ENDED DECEMBER 31, 2001

LINE NO.	DESCRIPTION	ALLOC FACTOR	INDUSTRIAL SM. VOL. (24)	INDUSTRIAL SM. VOL. AIR COND. (25)	INDUSTRIAL LG. VOL. (26)	INDUSTRIAL LG. VOL. AIR COND. (27)	INDUSTRIAL TRANSPORTATION (28)	PUBLIC AUTHORITY SM. VOL. (29)	PUBLIC AUTHORITY SM. VOL. AIR COND. (30)	PUBLIC AUTHORITY LG. VOL. (31)	PUBLIC AUTHORITY LG. VOL. AIR COND. (32)	PUBLIC AUTHORITY TRANSPORTATION (33)
87												
88	ACCT 903-CUST RECORDS & COLL											
89	DIRECT ASSIGNMENT TO TRANSMISSION	3,500										
90	CUSTOMER PERCENTAGE						40.00%					24.00%
91	ASSIGNMENT SUBTOTAL						1,400					840
92	BALANCE OF BILLING COSTS	3,686,700										
93	CUSTOMER PERCENTAGE		0.01%	0.00%	0.01%	0.00%		0.78%	0.00%	0.00%	0.00%	
94	ASSIGNMENT SUBTOTAL		520	0	195	0		28,618	0	163	0	
95	REPORTED CLASS ASSIGNMENT OF COLLECTION COSTS											
96	RESIDENTIAL	134,145										
97	CUSTOMER PERCENTAGE											
98	ASSIGNMENT SUBTOTAL											
99	SMALL VOLUME	28,506										
100	CUSTOMER PERCENTAGE		0.15%	0.00%				8.11%	0.00%			
101	ASSIGNMENT SUBTOTAL		42	0				2,312	0			
102	LARGE VOLUME	5,030										
103	CUSTOMER PERCENTAGE				26.09%	0.00%				21.74%	0.00%	
104	ASSIGNMENT SUBTOTAL				1,312	0				1,094	0	
105	ACCT 903-CUST RECORD & COLL ALLOC FACT(	CUST903	562	0	1,507	0	1,400	30,930	0	1,256	0	840
106												
107	ACCT 912-DEMO & SELLING											
108	ACCT 913-ADVERTISING EXPENSES											
109	WEIGHTING FACTOR		1.200	1.200	2.000	2.000	100.000	1.200	1.200	2.000	2.000	100.000
110	ACCT 912 - ALLOCATION FACTOR	CDA912	19	0	12	0	1,000	1,056	0	10	0	600
111	ACCT 913 - ALLOCATION FACTOR	CDA913	19	0	12	0	1,000	1,056	0	10	0	600
112												
113												
114	REVENUE RELATED											
115	--											
116	PRESENT ADJUSTED BASE REVENUE		304,310	0	902,488	0	670,137	2,028,097	0	354,475	0	380,495
117	PRESENT ADJUSTED PGA REVENUE		166,705	0	572,010	0	0	979,997	0	212,188	0	0
118	TOTAL PRESENT REVENUE		471,015	0	1,474,498	0	670,137	3,008,094	0	566,664	0	380,495
119												

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CITIZENS UTILITIES COMPANY - NORTHERN ARIZON
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACT(
12 MONTHS ENDED DECEMBER 31, 20

LINE NO.	DESCRIPTION	ALLOC FACTOR	SPECIAL GAS LIGHT SERVICE (34)	IRRIGATION (35)	COGENERATION (36)
87					
88	ACCT 903-CUST RECORDS & COLL				
89	DIRECT ASSIGNMENT TO TRANSMISSION	3,500			
90	CUSTOMER PERCENTAGE				
91	ASSIGNMENT SUBTOTAL				
92	BALANCE OF BILLING COSTS	3,686,700			
93	CUSTOMER PERCENTAGE		0.37%	0.01%	0.00%
94	ASSIGNMENT SUBTOTAL		13,789	228	0
95	REPORTED CLASS ASSIGNMENT OF COLLECTION COSTS				
96	RESIDENTIAL	134,145			
97	CUSTOMER PERCENTAGE				
98	ASSIGNMENT SUBTOTAL				
99	SMALL VOLUME	28,506			
100	CUSTOMER PERCENTAGE		3.91%	0.06%	
101	ASSIGNMENT SUBTOTAL		1,114	18	
102	LARGE VOLUME	5,030			
103	CUSTOMER PERCENTAGE				
104	ASSIGNMENT SUBTOTAL				
105	ACCT 903-CUST RECORD & COLL ALLOC FACT(	CUST903	14,903	246	0
106					
107	ACCT 912-DEMO & SELLING				
108	ACCT 913-ADVERTISING EXPENSES				
109	WEIGHTING FACTOR		1.200	1.200	2.000
110	ACCT 912 - ALLOCATION FACTOR	CDA912	5	8	0
111	ACCT 913 - ALLOCATION FACTOR	CDA913	5	8	0
112					
113					
114	REVENUE RELATED				
115	--				
116	PRESENT ADJUSTED BASE REVENUE		47,456	59,458	0
117	PRESENT ADJUSTED PGA REVENUE		19,790	36,205	0
118	TOTAL PRESENT REVENUE		67,246	95,664	0
119					

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CITIZENS UTILITIES COMPANY - SANTA CRUZ GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
12 MONTHS ENDED DECEMBER 31, 2001

LINE NO.	DESCRIPTION	ALLOC FACTOR	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)	COGENERATION (8)
1	DEMAND RELATED									
2										
3	PRODUCTION ALLOCATORS									
4	----------									
5	PRODUCTION DEMAND ALLOCATOR	DEMGAS								
6	DESIGN DAY DEMAND		56,291	38,608	11,057	1,422	5,204	0	0	0
7	COMMODITY + CAPACITY		2,187,442	1,462,840	535,776	35,976	152,850	0	0	0
8										
9										
10	TRANSMISSION ALLOCATORS									
11	----------									
12	PROPORTIONAL RESPONSIBILITY	TRANS	1.00000	0.68363	0.21874	0.01580	0.08183	0.00000	0.00000	0.00000
13	T2 DIRECT ASSIGNMENT	TTWO	1.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000
14										
15										
16										
17	DISTRIBUTION ALLOCATORS									
18	----------									
19	DISTRIBUTION ALLOCATOR	DISTR								
20	DISTRIBUTION MAINS		1.00000	0.68363	0.21874	0.01580	0.08183	0.00000	0.00000	0.00000
21	DISTRIBUTION REGULATORS		1.00000	0.68363	0.21874	0.01580	0.08183	0.00000	0.00000	0.00000
22										
23										
24	DESIGN DAY		56,291	38,608	11,057	1,422	5,204	0	0	0
25	PERCENT		1.00000	0.68586	0.19643	0.02525	0.09246	0.00000	0.00000	0.00000
26										
27	COMMODITY		5,051,437	3,378,122	1,237,262	83,078	352,975	0	0	0
28	PERCENT		1.00000	0.66874	0.24493	0.01645	0.06988	0.00000	0.00000	0.00000
29										
30	SEABOARD (50/50)		1.00000	0.67730	0.22068	0.02085	0.08117	0.00000	0.00000	0.00000
31	60% COMMODITY 40% DEMAND		1.00000	0.67559	0.22553	0.01997	0.07891	0.00000	0.00000	0.00000
32	40% COMMODITY 60% DEMAND		1.00000	0.67902	0.21583	0.02173	0.08342	0.00000	0.00000	0.00000
33	PROPORTIONAL RESPONSIBILITY		1.00	0.68	0.22	0.02	0.08	0.00	0.00	0.00
34										
35										
36	COMMODITY RELATED									
37	----------									
38	COMMODITY ALLOCATOR	GASSALES								
39	COMMODITY GAS COSTS		1,921,822	1,287,542	466,907	31,433	135,940	0	0	0
40	COMMODITY + CAPACITY		2,187,442	1,462,840	535,776	35,976	152,850	0	0	0
41	ANNUAL FIRM THERM THROUGHPUT		5,051,437	3,378,122	1,237,262	83,078	352,975	0	0	0
42	CARES		4,426,081	2,752,766	1,237,262	83,078	352,975	0	0	0
43										
44										

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CITIZENS UTILITIES COMPANY - SANTA CRUZ GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
0

LINE NO.	DESCRIPTION	ALLOC FACTOR	COMMERCIAL SM. VOL. (9)	COMMERCIAL LG. VOL. (10)	INDUSTRIAL SM. VOL. (11)	INDUSTRIAL LG. VOL. (12)	PUBLIC AUTHORITY SM. VOL. (13)	PUBLIC AUTHORITY LG. VOL. (14)
1	DEMAND RELATED							
2								
3	PRODUCTION ALLOCATORS							
4								
5	PRODUCTION DEMAND ALLOCATOR	DEMGAS						
6	DESIGN DAY DEMAND		11,057	0	1,422	0	5,204	0
7	COMMODITY + CAPACITY		535,776	0	35,976	0	152,850	0
8								
9								
10	TRANSMISSION ALLOCATORS							
11								
12	PROPORTIONAL RESPONSIBILITY	TRANS	0.21874	0.00000	0.01580	0.00000	0.08183	0.00000
13	T2 DIRECT ASSIGNMENT	TTWO	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000
14								
15								
16								
17	DISTRIBUTION ALLOCATORS							
18								
19	DISTRIBUTION ALLOCATOR	DISTR						
20	DISTRIBUTION MAINS		0.21874	0.00000	0.01580	0.00000	0.08183	0.00000
21	DISTRIBUTION REGULATORS		0.21874	0.00000	0.01580	0.00000	0.08183	0.00000
22								
23								
24	DESIGN DAY		11,057	0	1,422	0	5,204	0
25	PERCENT		0.19643	0.00000	0.02525	0.00000	0.09246	0.00000
26								
27	COMMODITY		1,237,262	0	83,078	0	352,975	0
28	PERCENT		0.24493	0.00000	0.01645	0.00000	0.06988	0.00000
29								
30	SEABOARD (50/50)		0.22068	0.00000	0.02085	0.00000	0.08117	0.00000
31	60% COMMODITY 40% DEMAND		0.22553	0.00000	0.01997	0.00000	0.07891	0.00000
32	40% COMMODITY 60% DEMAND		0.21583	0.00000	0.02173	0.00000	0.08342	0.00000
33	PROPORTIONAL RESPONSIBILITY		0.22	0.00	0.02	0.00	0.08	0.00
34								
35								
36	COMMODITY RELATED							
37								
38	COMMODITY ALLOCATOR	GASSALES						
39	COMMODITY GAS COSTS		466,907	0	31,433	0	135,940	0
40	COMMODITY + CAPACITY		535,776	0	35,976	0	152,850	0
41	ANNUAL FIRM THERM THROUGHPUT		1,237,262	0	83,078	0	352,975	0
42	CARES		1,237,262	0	83,078	0	352,975	0
43								
44								

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CITIZENS UTILITIES COMPANY - SANTA CRUZ GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
12 MONTHS ENDED DECEMBER 31, 2001

PRESENT RATE SCHEDULE DETAIL

			RESIDENTIAL				COMMERCIAL				
LINE NO.	DESCRIPTION	ALLOC FACTOR	RESIDENTIAL SERVICE (15)	RESIDENTIAL AIR COND. (16)	CARES (17)	CARES MED. LIFE SUPP. (18)	SM. VOL. (19)	SM. VOL. AIR COND. (20)	LG. VOL. (21)	LG. VOL. AIR COND. (22)	TRANSPORTATION (23)
1	DEMAND RELATED										
2											
3	PRODUCTION ALLOCATORS										
4	----------										
5	PRODUCTION DEMAND ALLOCATOR	DEMGAS									
6	DESIGN DAY DEMAND		31,503	0	7,099	6	11,057	0	0	0	0
7	COMMODITY + CAPACITY		1,192,040	0	270,569	231	535,776	0	0	0	0
8											
9											
10	TRANSMISSION ALLOCATORS										
11	----------										
12	PROPORTIONAL RESPONSIBILITY	TRANS	0.55751	0.00000	0.12602	0.00010	0.21874	0.00000	0.00000	0.00000	0.00000
13	T2 DIRECT ASSIGNMENT	TTWO	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
14											
15											
16											
17	DISTRIBUTION ALLOCATORS										
18	----------										
19	DISTRIBUTION ALLOCATOR	DISTR									
20	DISTRIBUTION MAINS		0.55751	0.00000	0.12602	0.00010	0.21874	0.00000	0.00000	0.00000	0.00000
21	DISTRIBUTION REGULATORS		0.55751	0.00000	0.12602	0.00010	0.21874	0.00000	0.00000	0.00000	0.00000
22											
23											
24	DESIGN DAY		31,503	0	7,099	6	11,057	0	0	0	0
25	PERCENT		0.55965	0.00000	0.12611	0.00011	0.19643	0.00000	0.00000	0.00000	0.00000
26											
27	COMMODITY		2,752,766	0	624,823	533	1,237,262	0	0	0	0
28	PERCENT		0.54495	0.00000	0.12369	0.00011	0.24493	0.00000	0.00000	0.00000	0.00000
29											
30	SEABOARD (50/50)		0.55230	0.00000	0.12490	0.00011	0.22068	0.00000	0.00000	0.00000	0.00000
31	60% COMMODITY 40% DEMAND		0.55083	0.00000	0.12466	0.00011	0.22553	0.00000	0.00000	0.00000	0.00000
32	40% COMMODITY 60% DEMAND		0.55377	0.00000	0.12514	0.00011	0.21583	0.00000	0.00000	0.00000	0.00000
33	PROPORTIONAL RESPONSIBILITY		0.56	0.00	0.13	0.00	0.22	0.00	0.00	0.00	0.00
34											
35											
36	COMMODITY RELATED										
37	----------										
38	COMMODITY ALLOCATOR	GASSALES									
39	COMMODITY GAS COSTS		1,049,171	0	238,168	203	466,907	0	0	0	0
40	COMMODITY + CAPACITY		1,192,040	0	270,569	231	535,776	0	0	0	0
41	ANNUAL FIRM THERM THROUGHPUT		2,752,766	0	624,823	533	1,237,262	0	0	0	0
42	CARES		2,752,766	0	0	0	1,237,262	0	0	0	0
43											
44											

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CITIZENS UTILITIES COMPANY - SANTA CRUZ GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
12 MONTHS ENDED DECEMBER 31, 2001

LINE NO.	DESCRIPTION	ALLOC FACTOR	INDUSTRIAL					PUBLIC AUTHORITY				
			SM. VOL.	SM. VOL. AIR COND.	LG. VOL.	LG. VOL. AIR COND.	TRANSPORTATION	SM. VOL.	SM. VOL. AIR COND.	LG. VOL.	LG. VOL. AIR COND.	TRANSPORTATION
			(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)	(33)
1	DEMAND RELATED											
2												
3	PRODUCTION ALLOCATORS											
4												
5	PRODUCTION DEMAND ALLOCATOR	DEMGAS										
6	DESIGN DAY DEMAND		1,422	0	0	0	0	5,204	0	0	0	0
7	COMMODITY + CAPACITY		35,976	0	0	0	0	152,850	0	0	0	0
8												
9												
10	TRANSMISSION ALLOCATORS											
11												
12	PROPORTIONAL RESPONSIBILITY	TRANS	0.01580	0.00000	0.00000	0.00000	0.00000	0.08183	0.00000	0.00000	0.00000	0.00000
13	T2 DIRECT ASSIGNMENT	TTWO	0.00000	0.00000	0.00000	0.00000	1.00000	0.00000	0.00000	0.00000	0.00000	0.00000
14												
15												
16												
17	DISTRIBUTION ALLOCATORS											
18												
19	DISTRIBUTION ALLOCATOR	DISTR										
20	DISTRIBUTION MAINS		0.01580	0.00000	0.00000	0.00000	0.00000	0.08183	0.00000	0.00000	0.00000	0.00000
21	DISTRIBUTION REGULATORS		0.01580	0.00000	0.00000	0.00000	0.00000	0.08183	0.00000	0.00000	0.00000	0.00000
22												
23												
24	DESIGN DAY		1,422	0	0	0	0	5,204	0	0	0	0
25	PERCENT		0.02525	0.00000	0.00000	0.00000	0.00000	0.09246	0.00000	0.00000	0.00000	0.00000
26												
27	COMMODITY		83,078	0	0	0	0	352,975	0	0	0	0
28	PERCENT		0.01645	0.00000	0.00000	0.00000	0.00000	0.06988	0.00000	0.00000	0.00000	0.00000
29												
30	SEABOARD (50/50)		0.02085	0.00000	0.00000	0.00000	0.00000	0.08117	0.00000	0.00000	0.00000	0.00000
31	60% COMMODITY 40% DEMAND		0.01997	0.00000	0.00000	0.00000	0.00000	0.07891	0.00000	0.00000	0.00000	0.00000
32	40% COMMODITY 60% DEMAND		0.02173	0.00000	0.00000	0.00000	0.00000	0.08342	0.00000	0.00000	0.00000	0.00000
33	PROPORTIONAL RESPONSIBILITY		0.02	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.00	0.00
34												
35												
36	COMMODITY RELATED											
37												
38	COMMODITY ALLOCATOR	GASSALES										
39	COMMODITY GAS COSTS		31,433	0	0	0	0	135,940	0	0	0	0
40	COMMODITY + CAPACITY		35,976	0	0	0	0	152,850	0	0	0	0
41	ANNUAL FIRM THERM THROUGHPUT		83,078	0	0	0	0	352,975	0	0	0	0
42	CARES		83,078	0	0	0	0	352,975	0	0	0	0
43												
44												

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CITIZENS UTILITIES COMPANY - SANTA CRUZ G.
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACT(
12 MONTHS ENDED DECEMBER 31, 20

LINE NO.	DESCRIPTION	ALLOC FACTOR	SPECIAL GAS LIGHT SERVICE (34)	IRRIGATION (35)	COGENERATION (36)
1	DEMAND RELATED				
2					
3	PRODUCTION ALLOCATORS				
4	--				
5	PRODUCTION DEMAND ALLOCATOR	DEMGAS			
6	DESIGN DAY DEMAND		0	0	0
7	COMMODITY + CAPACITY		0	0	0
8					
9					
10	TRANSMISSION ALLOCATORS				
11	--				
12	PROPORTIONAL RESPONSIBILITY	TRANS	0.00000	0.00000	0.00000
13	T2 DIRECT ASSIGNMENT	TTWO	0.00000	0.00000	0.00000
14					
15					
16					
17	DISTRIBUTION ALLOCATORS				
18	--				
19	DISTRIBUTION ALLOCATOR	DISTR			
20	DISTRIBUTION MAINS		0.00000	0.00000	0.00000
21	DISTRIBUTION REGULATORS		0.00000	0.00000	0.00000
22					
23					
24	DESIGN DAY		0	0	0
25	PERCENT		0.00000	0.00000	0.00000
26					
27	COMMODITY		0	0	0
28	PERCENT		0.00000	0.00000	0.00000
29					
30	SEABOARD (50/50)		0.00000	0.00000	0.00000
31	60% COMMODITY 40% DEMAND		0.00000	0.00000	0.00000
32	40% COMMODITY 60% DEMAND		0.00000	0.00000	0.00000
33	PROPORTIONAL RESPONSIBILITY		0.00	0.00	0.00
34					
35					
36	COMMODITY RELATED				
37	--				
38	COMMODITY ALLOCATOR	GASSALES			
39	COMMODITY GAS COSTS		0	0	0
40	COMMODITY + CAPACITY		0	0	0
41	ANNUAL FIRM THERM THROUGHPUT		0	0	0
42	CARES		0	0	0
43					
44					

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CITIZENS UTILITIES COMPANY - SANTA CRUZ GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
12 MONTHS ENDED DECEMBER 31, 2001

LINE NO.	DESCRIPTION	ALLOC FACTOR	TOTAL COMPANY (1)	RESIDENTIAL (2)	TOTAL COMMERCIAL (3)	TOTAL INDUSTRIAL (4)	TOTAL PUBLIC AUTH. (5)	SPECIAL GAS LIGHT SERVICE (6)	IRRIGATION (7)	COGENERATION (8)
45	CUSTOMER RELATED									
46	------------------------------									
47	YEAR END NUMBER OF CUSTOMERS	CUST10	7,071	6,453	545	6	66	0	0	0
48										
49										
50	ACCT 380-SERVICES									
51										
52	SERVICES ALLOCATION FACTOR	CUST380	3,631,069	3,315,295	279,999	1,866	33,908	0	0	0
53										
54	ACCT 381-METERS									
55										
56	METER ALLOCATION FACTOR	CUST381	821,220	772,682	43,038	262	5,238	0	0	0
57	DIRECT TO T2	CUST381T2	3	0	0	3	0	0	0	0
57										
58	ACCT 382-METER INSTALLATIONS									
59										
60	METER ALLOCATION FACTOR	CUST382	821,220	772,682	43,038	262	5,238	0	0	0
61										
62	ACCT 383-HOUSE REGULATORS									
63										
64	METER ALLOCATION FACTOR	CUST383	821,220	772,682	43,038	262	5,238	0	0	0
65										
66	ACCT 384-HOUSE REG. INSTALLATION									
67										
68	METER ALLOCATION FACTOR	CUST384	821,220	772,682	43,038	262	5,238	0	0	0
69										
70	ACCT 385-INDUSTRIAL REG EQUIPMENT (Currently Not Used)									
71										
72	IND REG EQUIP ALLOCATION FACTOR	CUST385	133,171	0	118,081	719	14,371	0	0	0
73										
74	CUSTOMER DEPOSITS									
75	REPORTED CLASS TOTAL			$ 37,516	$ 15,700					
76	TIMES RATE SCHEDULE THERM PERCENTAGE									
77	CUSTOMER DEPOSITS ALLOCATION FACTOR	CUSTDEP	53,216	37,516	11,609	779	3,312	0	0	0
78										
79	CUSTOMER ADVANCES (Currently Not Used)	CUSTADV	0	0	0	0	0	0	0	0
80	CONTR IN AID OF CONSTR-MAINS (Currently Not Used)	CONTMAIN	0	0	0	0	0	0	0	0
81	CONTR IN AID OF CONSTR-SERVICES (Currently Not Used)	CONTSERV	0	0	0	0	0	0	0	0
82										
83	487-FORFEITED DISCOUNTS (Currently Not Used)									
84	REPORTED CLASS TOTAL			$ 15,601.66	$ 0.55					
85	TIMES RATE SCHEDULE NUMBER OF CUSTOMER PERCENTAG									
86	FORFEITED DISCOUNTS ALLOCATION FACTOR	CUST487A	15,602.21	15,601.66	0.49	0.00	0.06	0.00	0.00	0.00
87										
88	487-MISCELLANEOUS SERVICE REV									
89	REPORTED CLASS TOTAL			$ 4,173.59						
90	TIMES RATE SCHEDULE NUMBER OF CUSTOMER PERCENTAG									
91	MISCELLANEOUS SERVICE REV ALLOC FACTOR	CUST487B	4,173.59	4,173.59	0.00	0.00	0.00	0.00	0.00	0.00
92										
93	ACCT 902-METER READ EXP									
94	WEIGHTING FACTOR									
95	METER READING EXPENSE ALLOCATION FACTOR	CUST902	4,281	3,936	305	2	37	0	0	0

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CITIZENS UTILITIES COMPANY - SANTA CRUZ GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
0

LINE NO.	DESCRIPTION	ALLOC FACTOR	COMMERCIAL SM. VOL. (9)	COMMERCIAL LG. VOL. (10)	INDUSTRIAL SM. VOL. (11)	INDUSTRIAL LG. VOL. (12)	PUBLIC AUTHORITY SM. VOL. (13)	PUBLIC AUTHORITY LG. VOL. (14)
45	CUSTOMER RELATED							
46	--							
47	YEAR END NUMBER OF CUSTOMERS	CUST10	545	0	3	3	66	0
48								
49								
50	ACCT 380-SERVICES							
51								
52	SERVICES ALLOCATION FACTOR	CUST380	279,999	0	1,541	325	33,908	0
53								
54	ACCT 381-METERS							
55								
56	METER ALLOCATION FACTOR	CUST381	43,038	0	262	0	5,238	0
57	DIRECT TO T2	CUST381T2	0	0	0	3	0	0
57								
58	ACCT 382-METER INSTALLATIONS							
59								
60	METER ALLOCATION FACTOR	CUST382	43,038	0	262	0	5,238	0
61								
62	ACCT 383-HOUSE REGULATORS							
63								
64	METER ALLOCATION FACTOR	CUST383	43,038	0	262	0	5,238	0
65								
66	ACCT 384-HOUSE REG. INSTALLATION							
67								
68	METER ALLOCATION FACTOR	CUST384	43,038	0	262	0	5,238	0
69								
70	ACCT 385-INDUSTRIAL REG EQUIPMENT (Currently Not Used)							
71								
72	IND REG EQUIP ALLOCATION FACTOR	CUST385	118,081	0	719	0	14,371	0
73								
74	CUSTOMER DEPOSITS							
75	REPORTED CLASS TOTAL							
76	TIMES RATE SCHEDULE THERM PERCENTAGE							
77	CUSTOMER DEPOSITS ALLOCATION FACTOR	CUSTDEP	11,609	0	779	0	3,312	0
78								
79	CUSTOMER ADVANCES (Currently Not Used)	CUSTADV	0	0	0	0	0	0
80	CONTR IN AID OF CONSTR-MAINS (Currently Not Used)	CONTMAIN	0	0	0	0	0	0
81	CONTR IN AID OF CONSTR-SERVICES (Currently Not Used)	CONTSERV	0	0	0	0	0	0
82								
83	487-FORFEITED DISCOUNTS (Currently Not Used)							
84	REPORTED CLASS TOTAL							
85	TIMES RATE SCHEDULE NUMBER OF CUSTOMER PERCENTAG							
86	FORFEITED DISCOUNTS ALLOCATION FACTOR	CUST487A	0.49	0.00	0.00	0.00	0.06	0.00
87								
88	487-MISCELLANEOUS SERVICE REV							
89	REPORTED CLASS TOTAL							
90	TIMES RATE SCHEDULE NUMBER OF CUSTOMER PERCENTAG							
91	MISCELLANEOUS SERVICE REV ALLOC FACTOR	CUST487B	0.00	0.00	0.00	0.00	0.00	0.00
92								
93	ACCT 902-METER READ EXP							
94	WEIGHTING FACTOR							
95	METER READING EXPENSE ALLOCATION FACTOR	CUST902	305	0	2	0	37	0

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CITIZENS UTILITIES COMPANY - SANTA CRUZ GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
12 MONTHS ENDED DECEMBER 31, 2001

PRESENT RATE SCHEDULE DETAIL

LINE NO.	DESCRIPTION	ALLOC FACTOR	RESIDENTIAL: RESIDENTIAL SERVICE (15)	RESIDENTIAL: RESIDENTIAL AIR COND. (16)	RESIDENTIAL: CARES (17)	RESIDENTIAL: CARES MED. LIFE SUPP. (18)	COMMERCIAL: SM. VOL. (19)	COMMERCIAL: SM. VOL. AIR COND. (20)	COMMERCIAL: LG. VOL. (21)	COMMERCIAL: LG. VOL. AIR COND. (22)	COMMERCIAL: TRANSPORTATION (23)
45	CUSTOMER RELATED										
46											
47	YEAR END NUMBER OF CUSTOMERS	CUST10	5,082	0	1,370	1	545	0	0	0	0
48											
49											
50	ACCT 380-SERVICES										
51											
52	SERVICES ALLOCATION FACTOR	CUST380	2,610,867	0	703,915	514	279,999	0	0	0	0
53											
54	ACCT 381-METERS										
55											
56	METER ALLOCATION FACTOR	CUST381	608,504	0	164,058	120	43,038	0	0	0	0
57	DIRECT TO T2	CUST381T2	0	0	0	0	0	0	0	0	0
57											
58	ACCT 382-METER INSTALLATIONS										
59											
60	METER ALLOCATION FACTOR	CUST382	608,504	0	164,058	120	43,038	0	0	0	0
61											
62	ACCT 383-HOUSE REGULATORS										
63											
64	METER ALLOCATION FACTOR	CUST383	608,504	0	164,058	120	43,038	0	0	0	0
65											
66	ACCT 384-HOUSE REG. INSTALLATION										
67											
68	METER ALLOCATION FACTOR	CUST384	608,504	0	164,058	120	43,038	0	0	0	0
69											
70	ACCT 385-INDUSTRIAL REG EQUIPMENT (Currently Not Used)										
71											
72	IND REG EQUIP ALLOCATION FACTOR	CUST385	0	0	0	0	118,081	0	0	0	0
73											
74	CUSTOMER DEPOSITS										
75	REPORTED CLASS TOTAL										
76	TIMES RATE SCHEDULE THERM PERCENTAGE		0.81	0.00	0.18	0.00	0.74				
77	CUSTOMER DEPOSITS ALLOCATION FACTOR	CUSTDEP	30,571	0	6,939	6	11,609	0	0	0	0
78											
79	CUSTOMER ADVANCES (Currently Not Used)	CUSTADV	0	0	0	0	0	0	0	0	0
80	CONTR IN AID OF CONSTR-MAINS (Currently Not Used)	CONTMAIN	0	0	0	0	0	0	0	0	0
81	CONTR IN AID OF CONSTR-SERVICES (Currently Not Used)	CONTSERV	0	0	0	0	0	0	0	0	0
82											
83	487-FORFEITED DISCOUNTS (Currently Not Used)										
84	REPORTED CLASS TOTAL										
85	TIMES RATE SCHEDULE NUMBER OF CUSTOMER PERCENTAG		0.79	0.00	0.21	0.00	0.89				
86	FORFEITED DISCOUNTS ALLOCATION FACTOR	CUST487A	12,286.65	0.00	3,312.60	2.42	0.49	0.00	0.00	0.00	0.00
87											
88	487-MISCELLANEOUS SERVICE REV										
89	REPORTED CLASS TOTAL										
90	TIMES RATE SCHEDULE NUMBER OF CUSTOMER PERCENTAG		0.79	0.00	0.21	0.00	0.89				
91	MISCELLANEOUS SERVICE REV ALLOC FACTOR	CUST487B	3,286.79	0.00	886.15	0.65	0.00	0.00	0.00	0.00	0.00
92											
93	ACCT 902-METER READ EXP										
94	WEIGHTING FACTOR		0.61	0.61	0.61	0.61	0.56				
95	METER READING EXPENSE ALLOCATION FACTOR	CUST902	3,100	0	836	1	305	0	0	0	0

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CITIZENS UTILITIES COMPANY - SANTA CRUZ GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
12 MONTHS ENDED DECEMBER 31, 2001

LINE NO.	DESCRIPTION	ALLOC FACTOR	INDUSTRIAL SM. VOL. (24)	SM. VOL. AIR COND. (25)	LG. VOL. (26)	LG. VOL. AIR COND. (27)	TRANSPORTATION (28)	PUBLIC AUTHORITY SM. VOL. (29)	SM. VOL. AIR COND. (30)	LG. VOL. (31)	LG. VOL. AIR COND. (32)	TRANSPORTATION (33)
45	CUSTOMER RELATED											
46	----------											
47	YEAR END NUMBER OF CUSTOMERS	CUST10	3	0	0	0	3	66	0	0	0	0
48												
49												
50	ACCT 380-SERVICES											
51												
52	SERVICES ALLOCATION FACTOR	CUST380	1,541	0	0	0	325	33,908	0	0	0	0
53												
54	ACCT 381-METERS											
55												
56	METER ALLOCATION FACTOR	CUST381	262	0	0	0	0	5,238	0	0	0	0
57	DIRECT TO T2	CUST381T2	0	0	0	0	3	0	0	0	0	0
57												
58	ACCT 382-METER INSTALLATIONS											
59												
60	METER ALLOCATION FACTOR	CUST382	262	0	0	0	0	5,238	0	0	0	0
61												
62	ACCT 383-HOUSE REGULATORS											
63												
64	METER ALLOCATION FACTOR	CUST383	262	0	0	0	0	5,238	0	0	0	0
65												
66	ACCT 384-HOUSE REG. INSTALLATION											
67												
68	METER ALLOCATION FACTOR	CUST384	262	0	0	0	0	5,238	0	0	0	0
69												
70	ACCT 385-INDUSTRIAL REG EQUIPMENT (Currently Not Used)											
71												
72	IND REG EQUIP ALLOCATION FACTOR	CUST385	719	0	0	0	0	14,371	0	0	0	0
73												
74	CUSTOMER DEPOSITS											
75	REPORTED CLASS TOTAL											
76	TIMES RATE SCHEDULE THERM PERCENTAGE		0.05					0.21				
77	CUSTOMER DEPOSITS ALLOCATION FACTOR	CUSTDEP	779	0	0	0	0	3,312	0	0	0	0
78												
79	CUSTOMER ADVANCES (Currently Not Used)	CUSTADV	0	0	0	0	0	0	0	0	0	0
80	CONTR IN AID OF CONSTR-MAINS (Currently Not Used)	CONTMAIN	0	0	0	0	0	0	0	0	0	0
81	CONTR IN AID OF CONSTR-SERVICES (Currently Not Used)	CONTSERV	0	0	0	0	0	0	0	0	0	0
82												
83	487-FORFEITED DISCOUNTS (Currently Not Used)											
84	REPORTED CLASS TOTAL											
85	TIMES RATE SCHEDULE NUMBER OF CUSTOMER PERCENTAG		0.01					0.11				
86	FORFEITED DISCOUNTS ALLOCATION FACTOR	CUST487A	0.00	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00
87												
88	487-MISCELLANEOUS SERVICE REV											
89	REPORTED CLASS TOTAL											
90	TIMES RATE SCHEDULE NUMBER OF CUSTOMER PERCENTAG		0.01					0.00				
91	MISCELLANEOUS SERVICE REV ALLOC FACTOR	CUST487B	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
92												
93	ACCT 902-METER READ EXP											
94	WEIGHTING FACTOR		0.56				0.00	0.56				
95	METER READING EXPENSE ALLOCATION FACTOR	CUST902	2	0	0	0	0	37	0	0	0	0

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CITIZENS UTILITIES COMPANY - SANTA CRUZ G.
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACT(
12 MONTHS ENDED DECEMBER 31, 20

LINE NO.	DESCRIPTION	ALLOC FACTOR	SPECIAL GAS LIGHT SERVICE (34)	IRRIGATION (35)	COGENERATION (36)
45	CUSTOMER RELATED				
46	--				
47	YEAR END NUMBER OF CUSTOMERS	CUST10	0	0	0
48					
49					
50	ACCT 380-SERVICES				
51					
52	SERVICES ALLOCATION FACTOR	CUST380	0	0	0
53					
54	ACCT 381-METERS				
55					
56	METER ALLOCATION FACTOR	CUST381	0	0	0
57	DIRECT TO T2	CUST381T2	0	0	0
57					
58	ACCT 382-METER INSTALLATIONS				
59					
60	METER ALLOCATION FACTOR	CUST382	0	0	0
61					
62	ACCT 383-HOUSE REGULATORS				
63					
64	METER ALLOCATION FACTOR	CUST383	0	0	0
65					
66	ACCT 384-HOUSE REG. INSTALLATION				
67					
68	METER ALLOCATION FACTOR	CUST384	0	0	0
69					
70	ACCT 385-INDUSTRIAL REG EQUIPMENT (Currently Not Used)				
71					
72	IND REG EQUIP ALLOCATION FACTOR	CUST385	0	0	0
73					
74	CUSTOMER DEPOSITS				
75	REPORTED CLASS TOTAL				
76	TIMES RATE SCHEDULE THERM PERCENTAGE				
77	CUSTOMER DEPOSITS ALLOCATION FACTOR	CUSTDEP	0	0	0
78					
79	CUSTOMER ADVANCES (Currently Not Used)	CUSTADV	0	0	0
80	CONTR IN AID OF CONSTR-MAINS (Currently Not Used)	CONTMAIN	0	0	0
81	CONTR IN AID OF CONSTR-SERVICES (Currently Not Used)	CONTSERV	0	0	0
82					
83	487-FORFEITED DISCOUNTS (Currently Not Used)				
84	REPORTED CLASS TOTAL				
85	TIMES RATE SCHEDULE NUMBER OF CUSTOMER PERCENTAG				
86	FORFEITED DISCOUNTS ALLOCATION FACTOR	CUST487A	0.00	0.00	0.00
87					
88	487-MISCELLANEOUS SERVICE REV				
89	REPORTED CLASS TOTAL				
90	TIMES RATE SCHEDULE NUMBER OF CUSTOMER PERCENTAG				
91	MISCELLANEOUS SERVICE REV ALLOC FACTOR	CUST487B	0.00	0.00	0.00
92					
93	ACCT 902-METER READ EXP				
94	WEIGHTING FACTOR				
95	METER READING EXPENSE ALLOCATION FACTOR	CUST902	0	0	0

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CITIZENS UTILITIES COMPANY - SANTA CRUZ GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
12 MONTHS ENDED DECEMBER 31, 2001

LINE NO.	DESCRIPTION	ALLOC FACTOR		GAS LIGHT SERVICE (1)	IRRIGATION (2)	COGENERATION (3)	(4)	(5)	SPECIAL (6)	(7)	(8)
96											
97	ACCT 903-CUST RECORDS & COLL										
98	BILLING COSTS		$	313,873							
99				313,873	286,441	24,206	280	2,946	0	0	0
100											
101	COLLECTION COSTS										
102	RESIDENTIAL		$	62,775							
103				62,775	62,775	0	0	0	0	0	0
104	COMMERCIAL		$	15,694							
105				15,694	0	13,848	160	1,685	0	0	0
106		CUST903		392,341	349,215	38,054	441	4,631	0	0	0
107											
108	ACCT 912-DEMO & SELLING										
109	ACCT 913-ADVERTISING EXPENSES										
110	WEIGHTING FACTOR										
111	ACCT 912 - ALLOCATION FACTOR	CDA912		7,491	6,453	654	304	80	0	0	0
112	ACCT 913 - ALLOCATION FACTOR	CDA913		7,491	6,453	654	304	80	0	0	0
113											
114											
115	REVENUE RELATED										
116	--										
117	PRESENT ADJUSTED BASE REVENUE			3,438,388	2,517,258	690,698	42,646	187,787	0	0	0
118	PRESENT ADJUSTEDPGA REVENUE			357,973	234,296	96,559	5,825	21,293	0	0	0
119	TOTAL PRESENT REVENUE			3,796,361	2,751,554	787,257	48,471	209,080	0	0	0

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CITIZENS UTILITIES COMPANY - SANTA CRUZ GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
0

LINE NO.	DESCRIPTION	ALLOC FACTOR	COMMERCIAL SM. VOL. (9)	COMMERCIAL LG. VOL. (10)	INDUSTRIAL SM. VOL. (11)	INDUSTRIAL LG. VOL. (12)	PUBLIC AUTHORITY SM. VOL. (13)	PUBLIC AUTHORITY LG. VOL. (14)
96								
97	ACCT 903-CUST RECORDS & COLL							
98	BILLING COSTS							
99			24,206	0	147	133	2,946	0
100								
101	COLLECTION COSTS							
102	RESIDENTIAL							
103			0	0	0	0	0	0
104	COMMERCIAL							
105			13,848	0	84	76	1,685	0
106		CUST903	38,054	0	232	209	4,631	0
107								
108	ACCT 912-DEMO & SELLING							
109	ACCT 913-ADVERTISING EXPENSES							
110	WEIGHTING FACTOR							
111	ACCT 912 - ALLOCATION FACTOR	CDA912	654	0	4	300	80	0
112	ACCT 913 - ALLOCATION FACTOR	CDA913	654	0	4	300	80	0
113								
114								
115	REVENUE RELATED							
116	--							
117	PRESENT ADJUSTED BASE REVENUE		690,698	0	42,646	0	187,787	0
118	PRESENT ADJUSTEDPGA REVENUE		96,559	0	5,825	0	21,293	0
119	TOTAL PRESENT REVENUE		787,257	0	48,471	0	209,080	0

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CITIZENS UTILITIES COMPANY - SANTA CRUZ GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
12 MONTHS ENDED DECEMBER 31, 2001

PRESENT RATE SCHEDULE DETAIL

LINE NO.	DESCRIPTION	ALLOC FACTOR	RESIDENTIAL				COMMERCIAL				
			RESIDENTIAL SERVICE (15)	RESIDENTIAL AIR COND. (16)	CARES (17)	CARES MED. LIFE SUPP. (18)	SM. VOL. (19)	SM. VOL. AIR COND. (20)	LG. VOL. (21)	LG. VOL. AIR COND. (22)	TRANSPORTATION (23)
96											
97	ACCT 903-CUST RECORDS & COLL										
98	BILLING COSTS										
99			225,578	0	60,818	44	24,206	0	0	0	0
100											
101	COLLECTION COSTS										
102	RESIDENTIAL										
103			49,436	0	13,329	10	0	0	0	0	0
104	COMMERCIAL										
105			0	0	0	0	13,848	0	0	0	0
106		CUST903	275,015	0	74,147	54	38,054	0	0	0	0
107											
108	ACCT 912-DEMO & SELLING										
109	ACCT 913-ADVERTISING EXPENSES										
110	WEIGHTING FACTOR		1.000	1.000	1.000	1.000	1.200	1.200	2.000	2.000	100.000
111	ACCT 912 - ALLOCATION FACTOR	CDA912	5,082	0	1,370	1	654	0	0	0	0
112	ACCT 913 - ALLOCATION FACTOR	CDA913	5,082	0	1,370	1	654	0	0	0	0
113											
114											
115	REVENUE RELATED										
116	------------------------------										
117	PRESENT ADJUSTED BASE REVENUE		2,041,649	0	475,207	402	690,698	0	0	0	0
118	PRESENT ADJUSTEDPGA REVENUE		189,193	0	45,053	49	96,559	0	0	0	0
119	TOTAL PRESENT REVENUE		2,230,842	0	520,260	452	787,257	0	0	0	0

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CITIZENS UTILITIES COMPANY - SANTA CRUZ GAS DIVISION
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACTORS
12 MONTHS ENDED DECEMBER 31, 2001

LINE NO.	DESCRIPTION	ALLOC FACTOR	INDUSTRIAL SM. VOL. (24)	SM. VOL. AIR COND. (25)	LG. VOL. (26)	LG. VOL. AIR COND. (27)	TRANSPORTATION (28)	PUBLIC AUTHORITY SM. VOL. (29)	SM. VOL. AIR COND. (30)	LG. VOL. (31)	LG. VOL. AIR COND. (32)	TRANSPORTATION (33)
96												
97	ACCT 903-CUST RECORDS & COLL											
98	BILLING COSTS											
99												
100			147	0	0	0	133	2,946	0	0	0	0
101	COLLECTION COSTS											
102	RESIDENTIAL											
103												
104	COMMERCIAL		0	0	0	0	0	0	0	0	0	0
105												
106			84	0	0	0	76	1,685	0	0	0	0
107		CUST903	232	0	0	0	209	4,631	0	0	0	0
108	ACCT 912-DEMO & SELLING											
109	ACCT 913-ADVERTISING EXPENSES											
110	WEIGHTING FACTOR		1.200	1.200	2.000	2.000	100.000	1.200	1.200	2.000	2.000	100.000
111	ACCT 912 - ALLOCATION FACTOR	CDA912	4	0	0	0	300	80	0	0	0	0
112	ACCT 913 - ALLOCATION FACTOR	CDA913	4	0	0	0	300	80	0	0	0	0
113												
114												
115	REVENUE RELATED											
116												
117	PRESENT ADJUSTED BASE REVENUE		42,646	0	0	0	0	187,787	0	0	0	0
118	PRESENT ADJUSTEDPGA REVENUE		5,825	0	0	0	0	21,293	0	0	0	0
119	TOTAL PRESENT REVENUE		48,471	0	0	0	0	209,080	0	0	0	0

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CITIZENS UTILITIES COMPANY - SANTA CRUZ G.
COST OF SERVICE STUDY
DEVELOPMENT OF ALLOCATION FACT(
12 MONTHS ENDED DECEMBER 31, 20

LINE NO.	DESCRIPTION	ALLOC FACTOR	SPECIAL GAS LIGHT SERVICE (34)	IRRIGATION (35)	COGENERATION (36)
96					
97	ACCT 903-CUST RECORDS & COLL				
98	BILLING COSTS				
99			0	0	0
100					
101	COLLECTION COSTS				
102	RESIDENTIAL				
103			0	0	0
104	COMMERCIAL				
105			0	0	0
106		CUST903	0	0	0
107					
108	ACCT 912-DEMO & SELLING				
109	ACCT 913-ADVERTISING EXPENSES				
110	WEIGHTING FACTOR		1.200	1.200	2.000
111	ACCT 912 - ALLOCATION FACTOR	CDA912	0	0	0
112	ACCT 913 - ALLOCATION FACTOR	CDA913	0	0	0
113					
114					
115	REVENUE RELATED				
116	--				
117	PRESENT ADJUSTED BASE REVENUE		0	0	0
118	PRESENT ADJUSTEDPGA REVENUE		0	0	0
119	TOTAL PRESENT REVENUE		0	0	0

Citizens Communications
NAGD Forecasted Gas Cost Allocation
Calendar Month Sales

Line	Rate Class	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Design Day Demand
	Calendar Month Sales by Class														
1	10-Residential	11,201,354	8,936,750	8,416,126	6,032,146	3,489,126	2,061,623	1,570,218	1,507,858	1,718,543	2,991,373	5,761,154	9,831,471	63,517,742	673,279
2	11-Residential A/C	696	548	557	366	230	143	196	199	151	141	159	478	3,863	38
3	12-CARES	158,183	115,638	109,574	76,423	45,530	28,597	21,244	20,189	24,217	39,521	82,931	142,310	864,356	9,367
4	13-CARES Med Life Support	134	109	81	46	23	15	13	13	15	51	108	141	751	9
5	20-Sm Vol Commercial	4,043,344	3,225,609	3,107,149	2,361,495	1,751,455	1,415,968	1,198,245	1,156,391	1,244,398	1,651,335	2,426,682	3,600,797	27,182,867	218,183
6	21-Sm Vol Commercial A/C	2,772	2,176	1,922	1,589	2,047	2,589	2,735	2,458	2,070	1,988	1,990	2,444	26,781	106
7	22-Lg Vol Commercial	267,907	197,656	200,422	165,116	137,610	93,726	69,398	71,038	88,342	140,402	212,623	271,965	1,916,206	15,604
8	23-Lg Vol Commercial A/C	-	-	-	-	-	-	-	-	-	-	-	-	-	0
9	T1-Lg Vol Commercial Transp	253,883	215,064	222,971	201,281	164,651	146,742	134,145	132,869	126,916	177,578	204,585	253,659	2,234,344	12,747
10	30-Sm Vol Industrial	97,706	89,032	110,805	88,471	67,223	64,224	52,908	55,693	57,154	56,215	66,731	103,514	909,678	5,849
11	31-Sm Vol Industrial A/C	-	-	-	-	-	-	-	-	-	-	-	-	-	0
12	32-Lg Vol Industrial	307,084	229,288	251,485	264,117	244,439	220,429	175,752	154,621	177,099	241,196	278,958	370,994	2,915,462	18,438
13	33-Lg Vol Industrial A/C	-	-	-	-	-	-	-	-	-	-	-	-	-	0
14	T1-Lg Vol Industrial Transp	1,239,167	1,015,540	1,002,920	1,233,625	1,233,353	1,010,191	1,147,399	1,355,385	1,579,366	1,031,195	1,033,303	1,355,023	14,236,466	63,680
15	40-Sm Vol Pub Auth	965,095	784,537	720,514	462,744	261,067	170,518	122,772	92,779	103,502	211,903	492,550	848,573	5,236,555	59,303
16	41-Sm Vol Pub Auth A/C	-	-	-	-	-	-	-	-	-	-	-	-	-	0
17	42-Lg Vol Pub Auth	221,106	111,164	133,737	101,821	57,455	32,679	23,844	25,031	34,710	72,306	117,810	172,411	1,104,074	11,786
18	T1-Lg Vol Pub Auth Transp	641,887	534,759	575,821	524,397	389,478	300,972	259,980	249,647	285,291	459,873	572,339	643,690	5,438,134	36,376
19	44-Gas Light Service	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,844	8,690	106,194	298
20	60-Irrigation Service	2,307	1,906	1,159	3,549	16,089	28,687	37,763	35,337	25,040	21,320	13,478	5,611	192,245	119
21	Total	19,411,491	15,468,643	14,864,110	11,526,052	7,868,644	5,585,970	4,825,477	4,868,374	5,475,679	7,105,260	11,274,247	17,611,772	125,885,718	1,125,182
22	Total Sales	17,276,554	13,703,280	13,062,397	9,566,749	6,081,161	4,128,066	3,283,953	3,130,473	3,484,106	5,436,615	9,464,020	15,359,400	103,976,773	1,012,379
23	Total Transportation	2,134,937	1,765,363	1,801,713	1,959,303	1,787,482	1,457,904	1,541,524	1,737,901	1,991,573	1,668,645	1,810,227	2,252,372	21,908,944	112,803

Citizens Communications
NAGD Forecasted Gas Cost Allocation
Demand Cost Allocation

Line	Rate Class	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Design Day Demand
	Allocation of Demand Costs														
1	10-Residential	299,108	284,977	299,108	294,397	299,108	294,397	299,108	299,108	294,397	299,108	294,397	299,108	3,556,319	
2	11-Residential A/C	17	16	17	17	17	17	17	17	17	17	17	17	201	
3	12-CARES	4,161	3,965	4,161	4,096	4,161	4,096	4,161	4,161	4,096	4,161	4,096	4,161	49,476	
4	13-CARES Med Life Support	4	4	4	4	4	4	4	4	4	4	4	4	49	
5	20-Sm Vol Commercial	96,929	92,350	96,929	95,403	96,929	95,403	96,929	96,929	95,403	96,929	95,403	96,929	1,152,462	
6	21-Sm Vol Commercial A/C	47	45	47	47	47	47	47	47	47	47	47	47	562	
7	22-Lg Vol Commercial	6,932	6,605	6,932	6,823	6,932	6,823	6,932	6,932	6,823	6,932	6,823	6,932	82,423	
8	23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	-	
9	T1-Lg Vol Commercial Transp	0	0	0	0	0	0	0	0	0	0	0	0	-	
10	30-Sm Vol Industrial	2,598	2,476	2,598	2,557	2,598	2,557	2,598	2,598	2,557	2,598	2,557	2,598	30,893	
11	31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	-	
12	32-Lg Vol Industrial	8,191	7,804	8,191	8,062	8,191	8,062	8,191	8,191	8,062	8,191	8,062	8,191	97,391	
13	33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	-	
14	T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	-	
15	40-Sm Vol Pub Auth	26,346	25,101	26,346	25,931	26,346	25,931	26,346	26,346	25,931	26,346	25,931	26,346	313,246	
16	41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	-	
17	42-Lg Vol Pub Auth	5,236	4,988	5,236	5,153	5,236	5,153	5,236	5,236	5,153	5,236	5,153	5,236	62,253	
18	T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	-	
19	44-Gas Light Service	132	126	132	130	132	130	132	132	130	132	130	132	1,573	
20	60-Irrigation Service	53	50	53	52	53	52	53	53	52	53	52	53	629	
21	Total	449,755	428,507	449,755	442,672	449,755	442,672	449,755	449,755	442,672	449,755	442,672	449,755	5,347,477	
22	Total Sales	449,755	428,507	449,755	442,672	449,755	442,672	449,755	449,755	442,672	449,755	442,672	449,755	5,347,477	
23	Total Transportation	-	-	-	-	-	-	-	-	-	-	-	-	-	

Citizens Communications
NAGD Forecasted Gas Cost Allocation
Commodity Cost Allocation

Line	Rate Class	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Design Day Demand
	Allocation of Commodity Costs														
1	10-Residential	4,622,070	3,587,936	3,222,456	2,162,271	1,236,621	728,713	559,689	542,267	617,120	1,074,189	2,209,567	3,978,481	24,541,380	
2	11-Residential A/C	287	220	213	131	81	50	70	71	54	50	61	194	1,484	
3	12-CARES	65,272	46,426	41,955	27,395	16,137	10,108	7,572	7,260	8,696	14,192	31,806	57,588	334,408	
4	13-CARES Med Life Support	55	44	31	17	8	5	5	5	5	18	42	57	292	
5	20-Sm Vol Commercial	1,668,425	1,295,021	1,189,698	846,497	620,753	500,496	427,103	415,870	446,857	592,987	930,702	1,457,127	10,391,536	
6	21-Sm Vol Commercial A/C	1,144	874	736	569	726	915	975	884	743	714	763	989	10,032	
7	22-Lg Vol Commercial	110,548	79,355	76,740	59,187	48,772	33,129	24,736	25,547	31,723	50,418	81,547	110,056	731,758	
8	23-Lg Vol Commercial A/C	-	-	-	-	-	-	-	-	-	-	-	-	-	
9	T1-Lg Vol Commercial Transp	-	-	-	-	-	-	-	-	-	-	-	-	-	
10	30-Sm Vol Industrial	40,317	35,745	42,426	31,713	23,825	22,701	18,859	20,029	20,524	20,187	25,593	41,889	343,807	
11	31-Sm Vol Industrial A/C	-	-	-	-	-	-	-	-	-	-	-	-	-	
12	32-Lg Vol Industrial	126,713	92,055	96,291	94,675	86,635	77,914	62,645	55,606	63,595	86,612	106,988	150,130	1,099,860	
13	33-Lg Vol Industrial A/C	-	-	-	-	-	-	-	-	-	-	-	-	-	
14	T1-Lg Vol Industrial Transp	-	-	-	-	-	-	-	-	-	-	-	-	-	
15	40-Sm Vol Pub Auth	398,232	314,977	275,878	165,874	92,528	60,272	43,761	33,366	37,167	76,093	188,907	343,390	2,030,446	
16	41-Sm Vol Pub Auth A/C	-	-	-	-	-	-	-	-	-	-	-	-	-	
17	42-Lg Vol Pub Auth	91,236	44,630	51,207	36,498	20,363	11,551	8,499	9,002	12,464	25,965	45,183	69,769	426,368	
18	T1-Lg Vol Pub Auth Transp	-	-	-	-	-	-	-	-	-	-	-	-	-	
19	44-Gas Light Service	3,658	3,560	3,395	3,178	3,142	3,134	3,160	3,188	3,184	3,184	3,392	3,517	39,692	
20	60-Irrigation Service	952	765	444	1,272	5,702	10,140	13,460	12,708	8,992	7,656	5,169	2,270	69,531	
21	Total	7,128,910	5,501,607	5,001,470	3,429,278	2,155,294	1,459,129	1,170,533	1,125,804	1,251,125	1,952,265	3,629,721	6,215,457	40,020,593	
22	Total Sales	7,128,910	5,501,607	5,001,470	3,429,278	2,155,294	1,459,129	1,170,533	1,125,804	1,251,125	1,952,265	3,629,721	6,215,457	40,020,593	
23	Total Transportation	-	-	-	-	-	-	-	-	-	-	-	-	-	

Citizens Communications
NAGD Forecasted Gas Cost Allocation
Total Gas Costs - Using Demand and Commodity Allocation

Line	Rate Class	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	Commodity + Capacity													
1	10-Residential	4,921,178	3,872,912	3,521,564	2,456,668	1,535,729	1,023,110	858,797	841,375	911,517	1,373,297	2,503,964	4,277,589	28,097,699
2	11-Residential A/C	304	236	230	148	98	67	87	88	71	67	78	210	1,685
3	12-CARES	69,433	50,391	46,116	31,490	20,298	14,204	11,733	11,422	12,792	18,353	35,902	61,749	383,883
4	13-CARES Med Life Support	59	48	35	21	12	9	9	9	9	22	46	61	341
5	20-Sm Vol Commercial	1,765,354	1,387,370	1,286,627	941,899	717,682	595,899	524,031	512,799	542,259	689,916	1,026,104	1,554,056	11,543,998
6	21-Sm Vol Commercial A/C	1,191	919	783	616	773	962	1,022	931	790	761	810	1,036	10,594
7	22-Lg Vol Commercial	117,480	85,960	83,672	66,010	55,704	39,952	31,668	32,480	38,546	57,350	88,370	116,988	814,180
8	23-Lg Vol Commercial A/C	-	-	-	-	-	-	-	-	-	-	-	-	-
9	T1-Lg Vol Commercial Transp	-	-	-	-	-	-	-	-	-	-	-	-	-
10	30-Sm Vol Industrial	42,915	38,220	45,025	34,271	26,424	25,258	21,457	22,627	23,081	22,785	28,151	44,487	374,700
11	31-Sm Vol Industrial A/C	-	-	-	-	-	-	-	-	-	-	-	-	-
12	32-Lg Vol Industrial	134,905	99,859	104,482	102,737	94,826	85,976	70,836	63,797	71,658	94,803	115,051	158,321	1,197,251
13	33-Lg Vol Industrial A/C	-	-	-	-	-	-	-	-	-	-	-	-	-
14	T1-Lg Vol Industrial Transp	-	-	-	-	-	-	-	-	-	-	-	-	-
15	40-Sm Vol Pub Auth	424,578	340,078	302,224	191,805	118,874	86,203	70,107	59,712	63,098	102,439	214,838	369,736	2,343,692
16	41-Sm Vol Pub Auth A/C	-	-	-	-	-	-	-	-	-	-	-	-	-
17	42-Lg Vol Pub Auth	96,472	49,619	56,443	41,652	25,599	16,704	13,735	14,238	17,617	31,201	50,337	75,005	488,621
18	T1-Lg Vol Pub Auth Transp	-	-	-	-	-	-	-	-	-	-	-	-	-
19	44-Gas Light Service	3,791	3,686	3,527	3,308	3,275	3,264	3,292	3,321	3,314	3,316	3,522	3,649	41,264
20	60-Irrigation Service	1,005	816	497	1,324	5,755	10,192	13,513	12,761	9,044	7,709	5,221	2,323	70,160
21	Total	7,578,665	5,930,114	5,451,225	3,871,950	2,605,049	1,901,801	1,620,288	1,575,559	1,693,797	2,402,020	4,072,393	6,665,212	45,368,070
22	Total Sales	7,578,665	5,930,114	5,451,225	3,871,950	2,605,049	1,901,801	1,620,288	1,575,559	1,693,797	2,402,020	4,072,393	6,665,212	45,368,070
23	Total Transportation	-	-	-	-	-	-	-	-	-	-	-	-	-

Citizens Communications
NAGD Forecasted Gas Cost Allocation
Total Gas Costs - Using Only Annual Volumetric Allocation

Line	Rate Class	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	Commodity + Capacity													
1	10-Residential													27,714,625
2	11-Residential A/C													1,686
3	12-CARES													377,144
4	13-CARES Med Life Support													328
5	20-Sm Vol Commercial													11,860,670
6	21-Sm Vol Commercial A/C													11,685
7	22-Lg Vol Commercial													836,096
8	23-Lg Vol Commercial A/C													-
9	T1-Lg Vol Commercial Transp													-
10	30-Sm Vol Industrial													396,919
11	31-Sm Vol Industrial A/C													-
12	32-Lg Vol Industrial													1,272,100
13	33-Lg Vol Industrial A/C													-
14	T1-Lg Vol Industrial Transp													-
15	40-Sm Vol Pub Auth													2,284,860
16	41-Sm Vol Pub Auth A/C													-
17	42-Lg Vol Pub Auth													481,739
18	T1-Lg Vol Pub Auth Transp													-
19	44-Gas Light Service													46,336
20	60-Irrigation Service													83,882
21	Total	-	-	-	-	-	-	-	-	-	-	-	-	45,368,070
22	Total Sales	-	-	-	-	-	-	-	-	-	-	-	-	45,368,070
23	Total Transportation	-	-	-	-	-	-	-	-	-	-	-	-	-

Citizens Communications
SCGD Forecasted Gas Cost Allocation
Calendar Month Sales

Line	Rate Class	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Design Day Demand
	Calendar Month Sales by Class														
1	10-Residential	543,255	390,147	317,841	267,945	132,053	83,601	82,413	85,206	89,856	120,091	219,063	421,296	2,752,766	31,503
2	11-Residential A/C	-	-	-	-	-	-	-	-	-	-	-	-	-	0
3	12-CARES	123,763	87,510	70,442	52,788	26,997	20,989	19,298	20,208	21,885	31,509	54,673	94,761	624,823	7,099
4	13-CARES Med Life Support	85	76	54	45	20	16	15	14	15	27	80	86	533	6
5	20-Sm Vol Commercial	205,772	143,799	119,642	111,024	63,547	52,998	51,854	52,783	59,674	91,378	122,524	162,265	1,237,262	11,057
6	21-Sm Vol Commercial A/C	-	-	-	-	-	-	-	-	-	-	-	-	-	0
7	22-Lg Vol Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-	0
8	23-Lg Vol Commercial A/C	-	-	-	-	-	-	-	-	-	-	-	-	-	0
9	T1-Lg Vol Commercial Transp	-	-	-	-	-	-	-	-	-	-	-	-	-	0
10	30-Sm Vol Industrial	14,885	10,734	7,632	8,402	10,529	5,555	93	70	2,236	4,845	4,909	13,188	83,078	1,422
11	31-Sm Vol Industrial A/C	-	-	-	-	-	-	-	-	-	-	-	-	-	0
12	32-Lg Vol Industrial	-	-	-	-	-	-	-	-	-	-	-	-	-	0
13	33-Lg Vol Industrial A/C	-	-	-	-	-	-	-	-	-	-	-	-	-	0
14	T1-Lg Vol Industrial Transp	-	-	-	-	-	-	-	-	-	-	-	-	-	0
15	40-Sm Vol Pub Auth	85,800	64,404	40,386	31,172	14,406	8,633	5,300	6,182	6,330	10,965	25,621	53,775	352,975	5,204
16	41-Sm Vol Pub Auth A/C	-	-	-	-	-	-	-	-	-	-	-	-	-	0
17	42-Lg Vol Pub Auth	-	-	-	-	-	-	-	-	-	-	-	-	-	0
18	T1-Lg Vol Pub Auth Transp	-	-	-	-	-	-	-	-	-	-	-	-	-	0
19	44-Gas Light Service	-	-	-	-	-	-	-	-	-	-	-	-	-	0
20	60-Irrigation Service	-	-	-	-	-	-	-	-	-	-	-	-	-	0
21	Total	973,561	696,671	555,998	471,375	247,552	171,792	158,973	164,464	179,995	258,814	426,870	745,373	5,051,437	56,291
22	Total Sales	973,561	696,671	555,998	471,375	247,552	171,792	158,973	164,464	179,995	258,814	426,870	745,373	5,051,437	56,291
23	Total Transportation	-	-	-	-	-	-	-	-	-	-	-	-	-	-

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Citizens Communications
SCGD Forecasted Gas Cost Allocation
Demand Cost Allocation

Line	Rate Class	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Design Day Demand
	Allocation of Demand Costs														
1	10-Residential	12,388	12,388	12,388	12,388	12,388	12,388	12,388	12,388	12,388	12,388	12,388	12,388	148,654	
2	*11-Residential A/C*	0	0	0	0	0	0	0	0	0	0	0	0	-	
3	12-CARES	2,791	2,791	2,791	2,791	2,791	2,791	2,791	2,791	2,791	2,791	2,791	2,791	33,496	
4	13-CARES Med Life Support	2	2	2	2	2	2	2	2	2	2	2	2	29	
5	20-Sm Vol Commercial	4,348	4,348	4,348	4,348	4,348	4,348	4,348	4,348	4,348	4,348	4,348	4,348	52,175	
6	21-Sm Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	-	
7	22-Lg Vol Commercial	0	0	0	0	0	0	0	0	0	0	0	0	-	
8	23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	-	
9	T1-Lg Vol Commercial Transp	0	0	0	0	0	0	0	0	0	0	0	0	-	
10	30-Sm Vol Industrial	559	559	559	559	559	559	559	559	559	559	559	559	6,708	
11	31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	-	
12	32-Lg Vol Industrial	0	0	0	0	0	0	0	0	0	0	0	0	-	
13	33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	-	
14	T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	-	
15	40-Sm Vol Pub Auth	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047	2,047	24,558	
16	41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	-	
17	42-Lg Vol Pub Auth	0	0	0	0	0	0	0	0	0	0	0	0	-	
18	T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	-	
19	44-Gas Light Service	0	0	0	0	0	0	0	0	0	0	0	0	-	
20	60-Irrigation Service	0	0	0	0	0	0	0	0	0	0	0	0	-	
21	Total	22,135	22,135	22,135	22,135	22,135	22,135	22,135	22,135	22,135	22,135	22,135	22,135	265,620	
22	Total Sales	22,135	22,135	22,135	22,135	22,135	22,135	22,135	22,135	22,135	22,135	22,135	22,135	265,620	
23	Total Transportation	-	-	-	-	-	-	-	-	-	-	-	-	-	

Citizens Communications
SCGD Forecasted Gas Cost Allocation
Commodity Cost Allocation

Line	Rate Class	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total	Design Day Demand
	Allocation of Commodity Costs														
1	10-Residential	220,870	154,336	119,911	94,638	46,117	29,117	28,943	30,192	31,794	42,491	82,782	167,979	1,049,171	
2	11-Residential A/C	-	-	-	-	-	-	-	-	-	-	-	-	-	
3	12-CARES	50,318	34,617	26,576	18,645	9,428	7,310	6,777	7,161	7,744	11,149	20,661	37,783	238,168	
4	13-CARES Med Life Support	35	30	20	16	7	6	5	5	5	9	30	34	203	
5	20-Sm Vol Commercial	83,660	56,885	45,137	39,214	22,192	18,458	18,211	18,704	21,115	32,332	46,301	64,698	466,907	
6	21-Sm Vol Commercial A/C	-	-	-	-	-	-	-	-	-	-	-	-	-	
7	22-Lg Vol Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-	
8	23-Lg Vol Commercial A/C	-	-	-	-	-	-	-	-	-	-	-	-	-	
9	T1-Lg Vol Commercial Transp	-	-	-	-	-	-	-	-	-	-	-	-	-	
10	30-Sm Vol Industrial	6,052	4,246	2,879	2,968	3,677	1,935	33	25	791	1,714	1,855	5,259	31,433	
11	31-Sm Vol Industrial A/C	-	-	-	-	-	-	-	-	-	-	-	-	-	
12	32-Lg Vol Industrial	-	-	-	-	-	-	-	-	-	-	-	-	-	
13	33-Lg Vol Industrial A/C	-	-	-	-	-	-	-	-	-	-	-	-	-	
14	T1-Lg Vol Industrial Transp	-	-	-	-	-	-	-	-	-	-	-	-	-	
15	40-Sm Vol Pub Auth	34,884	25,477	15,236	11,010	5,031	3,007	1,862	2,191	2,240	3,880	9,682	21,441	135,940	
16	41-Sm Vol Pub Auth A/C	-	-	-	-	-	-	-	-	-	-	-	-	-	
17	42-Lg Vol Pub Auth	-	-	-	-	-	-	-	-	-	-	-	-	-	
18	T1-Lg Vol Pub Auth Transp	-	-	-	-	-	-	-	-	-	-	-	-	-	
19	44-Gas Light Service	-	-	-	-	-	-	-	-	-	-	-	-	-	
20	60-Irrigation Service	-	-	-	-	-	-	-	-	-	-	-	-	-	
21	Total	395,819	275,592	209,759	166,490	86,452	59,832	55,831	58,277	63,689	91,575	161,311	297,195	1,921,822	
22	Total Sales	395,819	275,592	209,759	166,490	86,452	59,832	55,831	58,277	63,689	91,575	161,311	297,195	1,921,822	
23	Total Transportation	-	-	-	-	-	-	-	-	-	-	-	-	-	

Citizens Communications
SCGD Forecasted Gas Cost Allocation
Total Gas Costs - Using Demand and Commodity Allocation

Line	Rate Class	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	Commodity + Capacity													
1	10-Residential	233,258	166,724	132,299	107,026	58,504	41,504	41,331	42,580	44,182	54,879	95,170	180,367	1,197,825
2	11-Residential A/C	-	-	-	-	-	-	-	-	-	-	-	-	-
3	12-CARES	53,110	37,409	29,367	21,436	12,219	10,101	9,569	9,952	10,535	13,940	23,452	40,575	271,664
4	13-CARES Med Life Support	37	33	23	18	9	8	8	8	8	12	33	37	232
5	20-Sm Vol Commercial	88,008	61,233	49,485	43,562	26,540	22,806	22,559	23,051	25,463	36,680	50,649	69,046	519,082
6	21-Sm Vol Commercial A/C	-	-	-	-	-	-	-	-	-	-	-	-	-
7	22-Lg Vol Commercial	-	-	-	-	-	-	-	-	-	-	-	-	-
8	23-Lg Vol Commercial A/C	-	-	-	-	-	-	-	-	-	-	-	-	-
9	T1-Lg Vol Commercial Transp	-	-	-	-	-	-	-	-	-	-	-	-	-
10	30-Sm Vol Industrial	6,611	4,805	3,438	3,527	4,236	2,494	592	584	1,350	2,273	2,414	5,817	38,141
11	31-Sm Vol Industrial A/C	-	-	-	-	-	-	-	-	-	-	-	-	-
12	32-Lg Vol Industrial	-	-	-	-	-	-	-	-	-	-	-	-	-
13	33-Lg Vol Industrial A/C	-	-	-	-	-	-	-	-	-	-	-	-	-
14	T1-Lg Vol Industrial Transp	-	-	-	-	-	-	-	-	-	-	-	-	-
15	40-Sm Vol Pub Auth	36,930	27,524	17,283	13,056	7,078	5,053	3,908	4,237	4,286	5,926	11,729	23,488	160,498
16	41-Sm Vol Pub Auth A/C	-	-	-	-	-	-	-	-	-	-	-	-	-
17	42-Lg Vol Pub Auth	-	-	-	-	-	-	-	-	-	-	-	-	-
18	T1-Lg Vol Pub Auth Transp	-	-	-	-	-	-	-	-	-	-	-	-	-
19	44-Gas Light Service	-	-	-	-	-	-	-	-	-	-	-	-	-
20	60-Irrigation Service	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Total	417,954	297,727	231,894	188,625	108,587	81,967	77,966	80,412	85,824	113,710	183,446	319,330	2,187,442
22	Total Sales	417,954	297,727	231,894	188,625	108,587	81,967	77,966	80,412	85,824	113,710	183,446	319,330	2,187,442
23	Total Transportation	-	-	-	-	-	-	-	-	-	-	-	-	-

Citizens Communications
SCGD Forecasted Gas Cost Allocation
Total Gas Costs - Using Only Annual Volumetric Allocation

Line	Rate Class	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	Commodity + Capacity													
1	10-Residential													1,192,040
2	11-Residential A/C													-
3	12-CARES													270,569
4	13-CARES Med Life Support													231
5	20-Sm Vol Commercial													535,776
6	21-Sm Vol Commercial A/C													-
7	22-Lg Vol Commercial													-
8	23-Lg Vol Commercial A/C													-
9	T1-Lg Vol Commercial Transp													-
10	30-Sm Vol Industrial													35,976
11	31-Sm Vol Industrial A/C													-
12	32-Lg Vol Industrial													-
13	33-Lg Vol Industrial A/C													-
14	T1-Lg Vol Industrial Transp													-
15	40-Sm Vol Pub Auth													152,850
16	41-Sm Vol Pub Auth A/C													-
17	42-Lg Vol Pub Auth													-
18	T1-Lg Vol Pub Auth Transp													-
19	44-Gas Light Service													-
20	60-Irrigation Service													-
21	Total	-	-	-	-	-	-	-	-	-	-	-	-	2,187,442
22	Total Sales	-	-	-	-	-	-	-	-	-	-	-	-	2,187,442
23	Total Transportation	-	-	-	-	-	-	-	-	-	-	-	-	-

Citizens Communication Company - NAGD
Sales and Demand Model
Design Day Demand, Therms

DESIGN DAY
DEMAND, Therms

	Customer Class	Total Design Day Demand	Total Design Day Base Demand	Total Design Day Remaining Dem	Annual Load Factor
1	10-Residential	673,279	49,646	623,632	25.8%
2	11-Residential A/C	38	6	32	27.8%
3	12-CARES	9,367	668	8,698	25.3%
4	13-CARES Med Life Support	9	0	9	22.4%
5	20-Sm Vol Commercial	218,183	37,978	180,205	34.1%
6	21-Sm Vol Commercial A/C	106	84	23	69.0%
7	22-Lg Vol Commercial	15,604	2,265	13,339	33.6%
8	23-Lg Vol Commercial A/C	0	0	0	0.0%
9	T1-Lg Vol Commercial Transp	12,747	4,307	8,440	48.0%
10	30-Sm Vol Industrial	5,849	1,752	4,097	42.6%
11	31-Sm Vol Industrial A/C	0	0	0	0.0%
12	32-Lg Vol Industrial	18,438	5,329	13,109	43.3%
13	33-Lg Vol Industrial A/C	0	0	0	0.0%
14	T1-Lg Vol Industrial Transp	63,680	39,973	23,707	61.3%
15	40-Sm Vol Pub Auth	59,303	3,477	55,827	24.2%
16	41-Sm Vol Pub Auth A/C	0	0	0	0.0%
17	42-Lg Vol Pub Auth	11,786	788	10,997	25.7%
18	T1-Lg Vol Pub Auth Transp	36,376	8,220	28,156	41.0%
19	44-Gas Light Service	298	286	12	97.7%
20	60-Irrigation Service	119	74	45	442.0%
21	Total	1,125,182	154,853	970,328	30.7%
22	Total Sales	1,012,379	102,354	910,025	28.1%
23	Total Transportation	112,803	52,500	60,303	53.2%

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Exhibit JLH - 5
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Citizens Communication Company - NAGD
Sales and Demand Model
Calendar Month Weather Normalized Information

CALENDAR MONTH	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TOTAL	WINTER	SUMMER
YEAR END CUSTOMER ADJUSTED SALES, Therms															
1 10-Residential	11,201,354	8,936,750	8,416,126	6,032,146	3,489,126	2,061,623	1,570,218	1,507,858	1,718,543	2,991,373	5,761,154	9,831,471	63,517,742	53,668,126	9,849,615
2 11-Residential A/C	696	548	557	366	230	143	196	199	151	141	159	478	3,863	3,034	829
3 12-CARES	158,183	115,638	109,574	76,423	45,530	28,597	21,244	20,189	24,217	39,521	82,931	142,310	864,356	608,636	255,721
4 13-CARES Med Life Support	134	109	81	46	23	15	13	13	15	51	108	141	751	574	176
5 20-Sm Vol Commercial	4,043,344	3,225,609	3,107,149	2,361,495	1,751,455	1,415,968	1,198,245	1,156,391	1,244,398	1,651,335	2,426,682	3,600,797	27,182,867	20,516,531	6,666,336
6 21-Sm Vol Commercial A/C	2,772	2,176	1,922	1,589	2,047	2,589	2,735	2,458	2,070	1,988	1,990	2,444	26,781	14,941	11,839
7 22-Lg Vol Commercial	267,907	197,656	200,422	165,116	137,610	93,726	69,398	71,038	88,342	140,402	212,623	271,965	1,916,206	1,453,300	462,906
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Trans	253,883	215,064	222,971	201,281	164,651	146,742	134,145	132,869	126,916	177,578	204,585	253,659	2,234,344	1,516,095	718,249
10 30-Sm Vol Industrial	97,706	89,032	110,805	88,471	67,223	64,224	52,908	55,693	57,154	56,215	66,731	103,514	909,678	623,483	286,195
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	307,084	229,288	251,485	264,117	244,439	220,429	175,752	154,621	177,099	241,196	278,958	370,994	2,915,462	1,946,366	969,096
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	1,239,167	1,015,540	1,002,920	1,233,625	1,233,353	1,010,191	1,147,399	1,355,385	1,579,366	1,031,195	1,033,303	1,355,023	14,236,466	8,112,931	6,123,536
15 40-Sm Vol Pub Auth	965,095	784,537	720,514	462,744	261,067	170,518	122,772	92,779	103,502	211,903	492,550	848,573	5,236,555	4,535,080	701,475
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	221,106	111,164	133,737	101,821	57,455	32,679	23,844	25,031	34,710	72,306	117,810	172,411	1,104,074	915,504	188,569
18 T1-Lg Vol Pub Auth Transp	641,887	534,759	575,821	524,397	389,478	300,972	259,980	249,647	285,291	459,873	572,339	643,690	5,438,134	3,882,372	1,555,762
19 44-Gas Light Service	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,844	8,690	106,194	61,864	44,330
20 60-*Irrigation Service*	2,307	1,906	1,159	3,549	16,089	28,687	37,763	35,337	25,040	21,320	13,478	5,611	192,245	44,098	148,147
21 Total	19,411,491	15,468,643	14,864,110	11,526,052	7,868,644	5,585,970	4,825,477	4,868,374	5,475,679	7,105,260	11,274,247	17,611,772	125,885,718	97,902,936	27,982,782
22 Total Sales	17,276,554	13,703,280	13,062,397	9,566,749	6,081,161	4,128,066	3,283,953	3,130,473	3,484,106	5,436,615	9,464,020	15,359,400	103,976,773	84,391,538	19,585,235
23 Total Transportation	2,134,937	1,765,363	1,801,713	1,959,303	1,787,482	1,457,904	1,541,524	1,737,901	1,991,573	1,668,645	1,810,227	2,252,372	21,908,944	13,511,398	8,397,547

Citizens Communication Company - NAGD
Sales and Demand Model
Calendar Month Base Use, Therms

BASE USE
SALES, Therms

		Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TOTAL	WINTER	SUMMER
	Days in Month	31	28	31	30	31	30	31	31	30	31	30	31			
1	10-Residential	1,539,038	1,390,099	1,539,038	1,489,392	1,539,038	1,489,392	1,539,038	1,507,858	1,489,392	1,539,038	1,489,392	1,539,038	18,089,751	10,525,034	7,564,717
2	11-Residential A/C	197	178	197	191	197	143	196	197	151	141	159	197	2,145	1,317	828
3	12-CARES	20,716	18,711	20,716	20,048	20,716	20,048	20,716	20,189	20,048	20,716	20,048	20,716	243,390	100,908	142,482
4	13-CARES Med Life Suppori	13	12	13	13	13	13	13	13	13	13	13	13	154	64	90
5	20-Sm Vol Commercial	1,177,318	1,063,384	1,177,318	1,139,340	1,177,318	1,139,340	1,177,318	1,156,391	1,139,340	1,177,318	1,139,340	1,177,318	13,841,043	8,051,336	5,789,707
6	21-Sm Vol Commercial A/C	2,596	2,176	1,922	1,589	2,047	2,512	2,596	2,458	2,070	1,988	1,990	2,444	26,390	14,765	11,625
7	22-Lg Vol Commercial	70,218	63,423	70,218	67,953	70,218	67,953	69,398	70,218	67,953	70,218	67,953	70,218	825,941	480,201	345,740
8	23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	T1-Lg Vol Commercial Trans	133,507	120,587	133,507	129,200	133,507	129,200	133,507	132,869	126,916	133,507	129,200	133,507	1,569,014	913,015	655,999
10	30-Sm Vol Industrial	54,301	49,046	54,301	52,549	54,301	52,549	52,908	54,301	52,549	54,301	52,549	54,301	637,956	371,347	266,608
11	31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	32-Lg Vol Industrial	165,186	149,200	165,186	159,858	165,186	159,858	165,186	154,621	159,858	165,186	159,858	165,186	1,934,369	1,129,660	804,708
13	33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	T1-Lg Vol Industrial Transp	1,239,167	1,015,540	1,002,920	1,211,025	1,233,353	1,010,191	1,147,399	1,251,392	1,211,025	1,031,195	1,033,303	1,251,392	13,637,901	7,986,700	5,651,201
15	40-Sm Vol Pub Auth	107,776	97,346	107,776	104,299	107,776	104,299	107,776	92,779	103,502	107,776	104,299	107,776	1,253,179	737,047	516,132
16	41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	42-Lg Vol Pub Auth	24,437	22,072	24,437	23,649	24,437	23,649	23,844	24,437	23,649	24,437	23,649	24,437	287,135	167,119	120,016
18	T1-Lg Vol Pub Auth Transp	254,813	230,154	254,813	246,594	254,813	246,594	254,813	249,647	246,594	254,813	246,594	254,813	2,995,057	1,742,595	1,252,461
19	44-Gas Light Service	8,866	8,008	8,866	8,580	8,866	8,580	8,866	8,866	8,580	8,866	8,580	8,690	104,214	60,456	43,758
20	60-Irrigation Service	2,307	1,906	1,159	3,549	16,089	28,687	36,550	35,337	25,040	21,320	13,478	5,611	191,032	44,098	146,934
21	Total	4,800,457	4,231,843	4,562,388	4,657,827	4,807,876	4,483,007	4,740,124	4,761,573	4,676,679	4,610,833	4,490,404	4,815,658	55,638,669	32,325,663	23,313,006
22	Total Sales	3,172,970	2,865,562	3,171,148	3,071,008	3,186,203	3,097,023	3,204,405	3,127,665	3,092,144	3,191,318	3,081,307	3,175,945	37,436,697	21,683,353	15,753,345
23	Total Transportation	1,627,488	1,366,281	1,391,240	1,586,818	1,621,673	1,385,985	1,535,719	1,633,908	1,584,534	1,419,515	1,409,097	1,639,712	18,201,972	10,642,310	7,559,662

Sales and Demand Model

Calendar Month Remaining Use, Therms

REMAINING USE
SALES, Therms

Sales and Demand Model

Calendar Month Remaining Use, Therms

REMAINING USE
SALES, Therms

		Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TOTAL	WINTER	SUMMER
1	10-Residential	9,662,316	7,546,651	6,877,088	4,542,754	1,950,088	572,232	31,180	0	229,151	1,452,335	4,271,762	8,292,433	45,427,991	43,143,092	2,284,898
2	11-Residential A/C	499	370	360	175	33	0	0	1	0	0	0	281	1,718	1,717	1
3	12-CARES	137,467	96,926	88,857	56,375	24,814	8,549	528	0	4,169	18,805	62,883	121,594	620,966	507,727	113,239
4	13-CARES Med Life Support	121	98	68	33	10	2	0	0	3	38	96	128	597	511	86
5	20-Sm Vol Commercial	2,866,026	2,162,225	1,929,831	1,222,155	574,137	276,628	20,927	0	105,058	474,017	1,287,342	2,423,479	13,341,825	12,465,195	876,629
6	21-Sm Vol Commercial A/C	176	0	0	0	0	77	138	0	0	0	0	0	391	176	215
7	22-Lg Vol Commercial	197,689	134,233	130,204	97,163	67,392	25,773	0	820	20,389	70,184	144,670	201,747	1,090,264	973,099	117,166
8	23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	T1-Lg Vol Commercial Trans	120,376	94,477	89,464	72,081	31,144	17,542	638	0	0	44,071	75,385	120,152	665,330	603,080	62,250
10	30-Sm Vol Industrial	43,405	39,987	56,504	35,922	12,923	11,675	0	1,393	4,604	1,915	14,182	49,213	271,722	252,135	19,587
11	31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	32-Lg Vol Industrial	141,898	80,088	86,299	104,259	79,253	60,572	10,565	0	17,241	76,009	119,101	205,808	981,094	816,706	164,388
13	33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	T1-Lg Vol Industrial Transp	0	0	0	22,600	0	0	0	103,993	368,341	0	0	103,631	598,566	126,231	472,334
15	40-Sm Vol Pub Auth	857,319	687,192	612,738	358,445	153,291	66,219	14,997	0	0	104,127	388,251	740,798	3,983,376	3,798,033	185,343
16	41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	42-Lg Vol Pub Auth	196,669	89,092	109,300	78,172	33,018	9,030	0	594	11,061	47,869	94,161	147,974	816,939	748,386	68,554
18	T1-Lg Vol Pub Auth Transp	387,073	304,605	321,008	277,803	134,665	54,378	5,166	0	38,697	205,059	325,745	388,877	2,443,077	2,139,776	303,300
19	44-Gas Light Service	0	858	0	286	0	286	0	0	286	0	264	0	1,980	1,408	572
20	60-Irrigation Service	0	0	0	0	0	0	1,213	0	0	0	0	0	1,213	0	1,213
21	Total	14,611,034	11,236,800	10,301,722	6,868,225	3,060,768	1,102,963	85,352	106,801	799,000	2,494,427	6,783,843	12,796,114	70,247,048	65,577,273	4,669,776
22	Total Sales	14,103,585	10,837,718	9,891,250	6,495,741	2,894,958	1,031,043	79,548	2,808	391,961	2,245,298	6,382,712	12,183,454	66,540,076	62,708,185	3,831,891
23	Total Transportation	507,449	399,082	410,472	372,484	165,809	71,920	5,804	103,993	407,038	249,130	401,130	612,660	3,706,973	2,869,087	837,885

Citizens Communication Company - NAGD
Sales and Demand Model
Design Day Demand, Therms

DESIGN DAY
DEMAND, Therms

	Customer Class	Total Design Day Demand	Total Design Day Base Demand	Total Design Day Remaining Dem	Annual Load Factor
1	10-Residential	673,279	49,646	623,632	25.8%
2	11-Residential A/C	38	6	32	27.8%
3	12-CARES	9,367	668	8,698	25.3%
4	13-CARES Med Life Support	9	0	9	22.4%
5	20-Sm Vol Commercial	218,183	37,978	180,205	34.1%
6	21-Sm Vol Commercial A/C	106	84	23	69.0%
7	22-Lg Vol Commercial	15,604	2,265	13,339	33.6%
8	23-Lg Vol Commercial A/C	0	0	0	0.0%
9	T1-Lg Vol Commercial Transp	12,747	4,307	8,440	48.0%
10	30-Sm Vol Industrial	5,849	1,752	4,097	42.6%
11	31-Sm Vol Industrial A/C	0	0	0	0.0%
12	32-Lg Vol Industrial	18,438	5,329	13,109	43.3%
13	33-Lg Vol Industrial A/C	0	0	0	0.0%
14	T1-Lg Vol Industrial Transp	63,680	39,973	23,707	61.3%
15	40-Sm Vol Pub Auth	59,303	3,477	55,827	24.2%
16	41-Sm Vol Pub Auth A/C	0	0	0	0.0%
17	42-Lg Vol Pub Auth	11,786	788	10,997	25.7%
18	T1-Lg Vol Pub Auth Transp	36,376	8,220	28,156	41.0%
19	44-Gas Light Service	298	286	12	97.7%
20	60-Irrigation Service	119	74	45	442.0%
21	Total	1,125,182	154,853	970,328	30.7%
22	Total Sales	1,012,379	102,354	910,025	28.1%
23	Total Transportation	112,803	52,500	60,303	53.2%

Citizens Communication Company - NAGD
Sales and Demand Model
Computation of Design Day Demand, Therms - Page 1

DEVELOPMENT OF DESIGN DAY DEMAND, Therms

	Customer Class	Jan-01 1	Feb-01 2	Mar-01 3	Apr-01 4	May-01 5	Jun-01 6	Jul-01 7	Aug-01 8	Sep-01 9	Oct-01 10	Nov-01 11	Dec-01 12	Annual Usage	Consumption Summaries 7 Month Winter	5 Month Summer	7 mo. Wtr % of Annual	Design Day Demand
1	10-Residential	11,201,354	8,936,750	8,416,126	6,032,146	3,489,126	2,061,623	1,570,218	1,507,858	1,718,543	2,991,373	5,761,154	9,831,471	63,517,742	53,668,126	9,849,615	84.49%	673,279
2	11-Residential A/C	696	548	557	366	230	143	196	199	151	141	159	478	3,863	3,034	829	78.54%	38
3	12-CARES	158,183	115,638	109,574	76,423	45,530	28,597	21,244	20,189	24,217	39,521	82,931	142,310	864,356	608,636	255,721	70.41%	9,367
4	13-CARES Med Life Support	134	109	81	46	23	15	13	13	15	51	108	141	751	574	176	76.53%	9
5	*20-Sm Vol Commercial*	*4,043,344*	*3,225,609*	*3,107,149*	*2,361,495*	*1,751,455*	*1,415,968*	1,198,245	1,156,391	1,244,398	1,651,335	2,426,682	3,600,797	27,182,867	20,516,531	6,666,336	75.48%	218,183
6	21-Sm Vol Commercial A/C	2,772	2,176	1,922	1,589	2,047	2,589	2,735	2,458	2,070	1,988	1,990	2,444	26,781	14,941	11,839	55.79%	106
7	22-Lg Vol Commercial	267,907	197,656	200,422	165,116	137,610	93,726	69,398	71,038	88,342	140,402	212,623	271,965	1,916,206	1,453,300	462,906	75.84%	15,604
8	23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0
9	T1-Lg Vol Commercial Trans	253,883	215,064	222,971	201,281	164,651	146,742	134,145	132,869	126,916	177,578	204,585	253,659	2,234,344	1,516,095	718,249	67.85%	12,747
10	30-Sm Vol Industrial	97,706	89,032	110,805	88,471	67,223	64,224	52,908	55,693	57,154	56,215	66,731	103,514	909,678	623,483	286,195	68.54%	5,849
11	31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0
12	32-Lg Vol Industrial	307,084	229,288	251,485	264,117	244,439	220,429	175,752	154,621	177,099	241,196	278,958	370,994	2,915,462	1,946,366	969,096	66.76%	18,438
13	33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0
14	T1-Lg Vol Industrial Transp	1,239,167	1,015,540	1,002,920	1,233,625	1,233,353	1,010,191	1,147,399	1,355,385	1,579,366	1,031,195	1,033,303	1,355,023	14,236,466	8,112,931	6,123,536	56.99%	63,680
15	40-Sm Vol Pub Auth	965,095	*784,537*	*720,514*	*462,744*	*261,067*	*170,518*	122,772	92,779	103,502	211,903	492,550	848,573	5,236,555	4,535,080	701,475	86.60%	59,303
16	41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0
17	42-Lg Vol Pub Auth	221,106	111,164	133,737	101,821	57,455	32,679	23,844	25,031	34,710	72,306	117,810	172,411	1,104,074	915,504	188,569	82.92%	11,786
18	T1-Lg Vol Pub Auth Transp	641,887	534,759	575,821	524,397	389,478	300,972	259,980	249,647	285,291	459,873	572,339	643,690	5,438,134	3,882,372	1,555,762	71.39%	36,376
19	44-Gas Light Service	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,866	8,844	8,690	106,194	61,864	44,330	58.26%	298
20	60-Irrigation Service	2,307	1,906	1,159	3,549	16,089	28,687	37,763	35,337	25,040	21,320	13,478	5,611	192,245	44,098	148,147	22.94%	119
21	Total	19,411,491	15,468,643	14,864,110	11,526,052	7,868,644	5,585,970	4,825,477	4,868,374	5,475,679	7,105,260	11,274,247	17,611,772	125,885,718	97,902,936	27,982,782	77.77%	1,125,182
22	Total Sales	17,276,554	13,703,280	13,062,397	9,566,749	6,081,161	4,128,066	3,283,953	3,130,473	3,484,106	5,436,615	9,464,020	15,359,400	103,976,773	84,391,538	19,585,235	81.16%	1,012,379
23	Total Transportation	2,134,937	1,765,363	1,801,713	1,959,303	1,787,482	1,457,904	1,541,524	1,737,901	1,991,573	1,668,645	1,810,227	2,252,372	21,908,944	13,511,398	8,397,547	61.67%	112,803

Citizens Communication Company - NAGD
Sales and Demand Model
Computation of Design Day Demand, Therms - Page 2

	Customer Class	Normal Degree Days in Calendar Month Jan-01 1	Feb-01 2	Mar-01 3	Apr-01 4	May-01 5	Jun-01 6	Jul-01 7	Aug-01 8	Sep-01 9	Oct-01 10	Nov-01 11	Dec-01 12	Total Yr's DD's
1	10-Residential	894	726	626	443	200	67	13	17	78	351	670	915	5,002
2	11-Residential A/C	894	726	626	443	200	67	13	17	78	351	670	915	5,002
3	12-CARES	894	726	626	443	200	67	13	17	78	351	670	915	5,002
4	13-CARES Med Life Support	894	726	626	443	200	67	13	17	78	351	670	915	5,002
5	20-Sm Vol Commercial	894	726	626	443	200	67	13	17	78	351	670	915	5,002
6	21-Sm Vol Commercial A/C	894	726	626	443	200	67	13	17	78	351	670	915	5,002
7	22-Lg Vol Commercial	894	726	626	443	200	67	13	17	78	351	670	915	5,002
8	23-Lg Vol Commercial A/C	894	726	626	443	200	67	13	17	78	351	670	915	5,002
9	T1-Lg Vol Commercial Trans	894	726	626	443	200	67	13	17	78	351	670	915	5,002
10	30-Sm Vol Industrial	894	726	626	443	200	67	13	17	78	351	670	915	5,002
11	31-Sm Vol Industrial A/C	894	726	626	443	200	67	13	17	78	351	670	915	5,002
12	32-Lg Vol Industrial	894	726	626	443	200	67	13	17	78	351	670	915	5,002
13	33-Lg Vol Industrial A/C	894	726	626	443	200	67	13	17	78	351	670	915	5,002
14	T1-Lg Vol Industrial Transp	894	726	626	443	200	67	13	17	78	351	670	915	5,002
15	40-Sm Vol Pub Auth	894	726	626	443	200	67	13	17	78	351	670	915	5,002
16	41-Sm Vol Pub Auth A/C	894	726	626	443	200	67	13	17	78	351	670	915	5,002
17	42-Lg Vol Pub Auth	894	726	626	443	200	67	13	17	78	351	670	915	5,002
18	T1-Lg Vol Pub Auth Transp	894	726	626	443	200	67	13	17	78	351	670	915	5,002
19	44-Gas Light Service	894	726	626	443	200	67	13	17	78	351	670	915	5,002
20	60-Irrigation Service	894	726	626	443	200	67	13	17	78	351	670	915	5,002
21	Total													
22	Total Sales													
23	Total Transportation													

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Citizens Communication Company - NAGD
Sales and Demand Model
Computation of Design Day Demand, Therms - Page 3

	Customer Class	Use Per Customer Jan-01 1	Feb-01 2	Mar-01 3	Apr-01 4	May-01 5	Jun-01 6	Jul-01 7	Aug-01 8	Sep-01 9	Oct-01 10	Nov-01 11	Dec-01 12	Total Yr's
1	10-Residential	111	89	83	60	35	20	16	15	17	30	57	97	629
2	11-Residential A/C	139	110	111	73	46	29	39	40	30	28	32	96	773
3	12-CARES	102	75	71	49	29	18	14	13	16	25	54	92	558
4	13-CARES Med Life Support	134	109	81	46	23	15	13	13	15	51	108	141	751
5	20-Sm Vol Commercial	425	339	326	248	184	149	126	121	131	173	255	378	2,856
6	21-Sm Vol Commercial A/C	693	544	481	397	512	647	684	614	517	497	498	611	6,695
7	22-Lg Vol Commercial	22,326	16,471	16,702	13,760	11,468	7,810	5,783	5,920	7,362	11,700	17,719	22,664	159,684
8	23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
9	T1-Lg Vol Commercial Trans	28,209	23,896	24,775	22,365	18,295	16,305	14,905	14,763	14,102	19,731	22,732	28,184	248,260
10	30-Sm Vol Industrial	6,107	5,565	6,925	5,529	4,201	4,014	3,307	3,481	3,572	3,513	4,171	6,470	56,855
11	31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
12	32-Lg Vol Industrial	51,181	38,215	41,914	44,019	40,740	36,738	29,292	25,770	29,517	40,199	46,493	61,832	485,910
13	33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
14	T1-Lg Vol Industrial Transp	123,917	101,554	100,292	123,362	123,335	101,019	114,740	135,539	157,937	103,120	103,330	135,502	1,423,647
15	40-Sm Vol Pub Auth	1,097	892	819	526	297	194	140	105	118	241	560	964	5,951
16	41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
17	42-Lg Vol Pub Auth	44,221	22,233	26,747	20,364	11,491	6,536	4,769	5,006	6,942	14,461	23,562	34,482	220,815
18	T1-Lg Vol Pub Auth Transp	106,981	89,127	95,970	87,399	64,913	50,162	43,330	41,608	47,548	76,645	95,390	107,282	906,356
19	44-Gas Light Service	2,217	2,217	2,217	2,217	2,217	2,217	2,217	2,217	2,217	2,217	2,211	2,173	26,549
20	60-Irrigation Service	330	272	166	507	2,298	4,098	5,395	5,048	3,577	3,046	1,925	802	27,464

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Citizens Communication Company - NAGD
Sales and Demand Model
Computation of Design Day Demand, Therms - Page 4

	Customer Class	Monthly Base Use per customer	Regression Prediction		Load at 62.1	Conventional Weather Norm			Use in Wtr Peak Mo	Peak Month Adjustment		Load at 62.1	Design Day Load Estimate	Adjusted to Sales System Total
			Use per Deg Day per customer	R -Square		Monthly Base Use	Use per Deg Day	Load at 62.1		DD in Peak Mo.	Use per Deg Day			
											60%		90%	1,012,379
1	10-Residential	11	0.10	92%	657,327	1,539,038	9,853	661,381	8,936,750	726	9,991	675,482	657,327	673,279
2	11-Residential A/C	26	0.09	62%	33	141	0	34	557	626	0	37	37	38
3	12-CARES	9	0.09	94%	9,145	20,716	135	9,030	115,638	726	140	9,154	9,145	9,367
4	13-CARES Med Life Support	3	0.14	97%	9	13	0	8	109	726	0	9	9	9
5	20-Sm Vol Commercial	113	0.30	93%	213,014	1,177,318	2,855	215,255	3,225,609	726	2,865	215,447	213,014	218,183
6	21-Sm Vol Commercial A/C	566	-0.02	1%	69	1,988	1	104	2,176	726	1	96	104	106
7	22-Lg Vol Commercial	6,135	17.21	97%	15,234	70,218	235	16,844	200,422	626	206	15,157	15,234	15,604
8	23-Lg Vol Commercial A/C	0	0.00	#DIV/0!	0	0	0	0	0	726	0	0	0	0
9	T1-Lg Vol Commercial Trans	14,625	14.55	96%	12,445	133,507	138	12,892	222,971	626	131	12,754	12,445	12,747
10	30-Sm Vol Industrial	3,436	3.12	68%	4,905	54,301	56	5,256	110,805	626	50	5,710	5,710	5,849
11	31-Sm Vol Industrial A/C	0	0.00	#DIV/0!	0	0	0	0	0	726	0	0	0	0
12	32-Lg Vol Industrial	30,050	25.05	73%	15,245	165,186	204	18,001	264,117	443	150	15,809	18,001	18,438
13	33-Lg Vol Industrial A/C	0	0.00	#DIV/0!	0	0	0	0	0	726	0	0	0	0
14	T1-Lg Vol Industrial Transp	123,243	-11.05	4%	33,546	1,031,195	407	58,551	1,233,625	443	457	62,171	62,171	63,680
15	40-Sm Vol Pub Auth	70	1.02	92%	57,898	107,776	862	57,023	784,537	726	900	60,185	57,898	59,303
16	41-Sm Vol Pub Auth A/C	0	0.00	#DIV/0!	0	0	0	0	0	726	0	0	0	0
17	42-Lg Vol Pub Auth	3,786	35.07	91%	11,506	24,437	177	11,799	133,737	626	175	11,674	11,506	11,786
18	T1-Lg Vol Pub Auth Transp	45,896	71.10	95%	35,514	254,813	521	40,543	575,821	626	427	36,615	35,514	36,376
19	44-Gas Light Service	2,220	-0.02	24%	287	8,866	(0)	283	8,866	726	0	291	291	298
20	60-Irrigation Service	4,342	-4.93	77%	(1,144)	21,320	(14)	(176)	3,549	443	0	116	116	119
21	Total	234,530			1,065,033	4,610,833		1,106,828	15,819,290			1,120,708	1,098,524	1,125,182
22	Total Sales	50,766			983,528	3,191,318		994,842	13,786,873			1,009,167	988,393	1,012,379
23	Total Transportation	183,764			81,506	1,419,515		111,986	2,032,417			111,541	110,131	112,803

Citizens Communication Company - NAGD
Sales and Demand Model
Proportional Responsibility Allocator

DEVELOPMENT OF PR ALLOCATOR

	DATE	Tot Cal Month Sales 1	Ranking 2	Percent of Peak Month 3	Next Ranked Month 4	Next Ranked Month Percent of Peak Month 5	Difference 6	Individual Weighting Factors 7		Cumulative Weighting Factors 8
1	Jan-01	19,411,491	1	100.0000%	2	90.7286%	9.2714%	9.2714%		27.3201%
2	Feb-01	15,468,643	3	79.6881%	4	76.5738%	3.1143%	1.0381%		12.5285%
3	Mar-01	14,864,110	4	76.5738%	5	59.3775%	17.1963%	4.2991%		11.4904%
4	Apr-01	11,526,052	5	59.3775%	6	58.0803%	1.2972%	0.2594%		7.1913%
5	May-01	7,868,644	7	40.5360%	8	36.6034%	3.9326%	0.5618%		4.0078%
6	Jun-01	5,585,970	9	28.7766%	10	28.2084%	0.5682%	0.0631%		2.4677%
7	Jul-01	4,825,477	12	24.8589%		0.0000%	24.8589%	2.0716%		2.0716%
8	Aug-01	4,868,374	11	25.0799%	12	24.8589%	0.2210%	0.0201%		2.0917%
9	Sep-01	5,475,679	10	28.2084%	11	25.0799%	3.1286%	0.3129%		2.4045%
10	Oct-01	7,105,260	8	36.6034%	9	28.7766%	7.8268%	0.9783%		3.4460%
11	Nov-01	11,274,247	6	58.0803%	7	40.5360%	17.5443%	2.9240%		6.9318%
12	Dec-01	17,611,772	2	90.7286%	3	79.6881%	11.0405%	5.5203%		18.0487%
	TOTAL	125,885,718								100.0000%
									WINTER	87.5186%
									SUMMER	12.4814%
										100.0000%

Citizens Communication Company - NAGD
Sales and Demand Model
PR Allocator Weighted By Class Normalized Calendar Month Sales

	PR Monthly Weighting	Jan-01 27.32%	Feb-01 12.53%	Mar-01 11.49%	Apr-01 7.19%	May-01 4.01%	Jun-01 2.47%	Jul-01 2.07%	Aug-01 2.09%	Sep-01 2.40%	Oct-01 3.45%	Nov-01 6.93%	Dec-01 18.05%	TOTAL	ALLOCATION FACTOR
1	10-Residential	3,060,225	1,119,637	967,043	433,789	139,837	50,874	32,528	31,539	41,323	103,083	399,354	1,774,454	8,153,686	55.21%
2	11-Residential A/C	190	69	64	26	9	4	4	4	4	5	11	86	476	0.00%
3	12-CARES	43,216	14,488	12,590	5,496	1,825	706	440	422	582	1,362	5,749	25,685	112,560	0.76%
4	13-CARES Med Life Support	37	14	9	3	1	0	0	0	0	2	8	26	100	0.00%
5	20-Sm Vol Commercial	1,104,647	404,119	357,023	169,822	70,195	34,941	24,823	24,188	29,922	56,905	168,214	649,898	3,094,695	20.95%
6	21-Sm Vol Commercial A/C	757	273	221	114	82	64	57	51	50	69	138	441	2,317	0.02%
7	22-Lg Vol Commercial	73,193	24,763	23,029	11,874	5,515	2,313	1,438	1,486	2,124	4,838	14,739	49,086	214,398	1.45%
8	23-Lg Vol Commercial A/C	-	-	-	-	-	-	-	-	-	-	-	-	0	0.00%
9	T1-Lg Vol Commercial Trans	69,361	26,944	25,620	14,475	6,599	3,621	2,779	2,779	3,052	6,119	14,182	45,782	221,313	1.50%
10	30-Sm Vol Industrial	26,693	11,154	12,732	6,362	2,694	1,585	1,096	1,165	1,374	1,937	4,626	18,683	90,102	0.61%
11	31-Sm Vol Industrial A/C	-	-	-	-	-	-	-	-	-	-	-	-	0	0.00%
12	32-Lg Vol Industrial	83,896	28,726	28,897	18,993	9,797	5,439	3,641	3,234	4,258	8,312	19,337	66,960	281,490	1.91%
13	33-Lg Vol Industrial A/C	-	-	-	-	-	-	-	-	-	-	-	-	0	0.00%
14	T1-Lg Vol Industrial Transp	338,542	127,232	115,239	88,713	49,430	24,928	23,769	28,350	37,976	35,535	71,627	244,564	1,185,906	8.03%
15	40-Sm Vol Pub Auth	263,665	98,290	82,790	33,277	10,463	4,208	2,543	1,941	2,489	7,302	34,143	153,157	694,268	4.70%
16	41-Sm Vol Pub Auth A/C	-	-	-	-	-	-	-	-	-	-	-	-	0	0.00%
17	42-Lg Vol Pub Auth	60,406	13,927	15,367	7,322	2,303	806	494	524	835	2,492	8,166	31,118	143,760	0.97%
18	T1-Lg Vol Pub Auth Transp	175,364	66,997	66,164	37,711	15,610	7,427	5,386	5,222	6,860	15,847	39,674	116,178	558,439	3.78%
19	44-Gas Light Service	2,422	1,111	1,019	638	355	219	184	185	213	306	613	1,568	8,833	0.06%
20	60-Irrigation Service	630	239	133	255	645	708	782	739	602	735	934	1,013	7,415	0.05%
21	Total	5,303,245	1,937,983	1,707,939	828,871	315,360	137,842	99,963	101,830	131,664	244,847	781,513	3,178,699	14,769,757	100.00%
22	Total Sales	4,719,977	1,716,810	1,500,916	687,972	243,721	101,866	68,029	65,479	83,776	187,346	656,031	2,772,175	12,804,099	86.69%
23	Total Transportation	583,268	221,173	207,023	140,899	71,639	35,976	31,934	36,351	47,888	57,501	125,482	406,524	1,965,658	13.31%

Citizens Communication Company - SCGD
Sales and Demand Model
Calendar Month Weather Normalized Information

CALENDAR MONTH	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TOTAL	WINTER	SUMMER
YEAR END CUSTOMER ADJUSTED SALES, Therms															
1 10-Residential	543,255	390,147	317,841	267,945	132,053	83,601	82,413	85,206	89,856	120,091	219,063	421,296	2,752,766	2,291,600	461,167
2 11-Residential A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3 12-CARES	123,763	87,510	70,442	52,788	26,997	20,989	19,298	20,208	21,885	31,509	54,673	94,761	624,823	431,150	193,673
4 13-CARES Med Life Support	85	76	54	45	20	16	15	14	15	27	80	86	533	381	152
5 20-Sm Vol Commercial	205,772	143,799	119,642	111,024	63,547	52,998	51,854	52,783	59,674	91,378	122,524	162,265	1,237,262	928,574	308,688
6 21-Sm Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7 22-Lg Vol Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8 23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 T1-Lg Vol Commercial Trans	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10 30-Sm Vol Industrial	14,885	10,734	7,632	8,402	10,529	5,555	93	70	2,236	4,845	4,909	13,188	83,078	70,280	12,798
11 31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12 32-Lg Vol Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14 T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15 40-Sm Vol Pub Auth	85,800	64,404	40,386	31,172	14,406	8,633	5,300	6,182	6,330	10,965	25,621	53,775	352,975	315,564	37,411
16 41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17 42-Lg Vol Pub Auth	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18 T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19 44-Gas Light Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20 60-Irrigation Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21 Total	973,561	696,671	555,998	471,375	247,552	171,792	158,973	164,464	179,995	258,814	426,870	745,373	5,051,437	4,037,549	1,013,888
22 Total Sales	973,561	696,671	555,998	471,375	247,552	171,792	158,973	164,464	179,995	258,814	426,870	745,373	5,051,437	4,037,549	1,013,888
23 Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Citizens Communication Company - SCGD
Sales and Demand Model
Calendar Month Base Use, Therms

BASE USE
SALES, Therms

		Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TOTAL	WINTER	SUMMER
	Days in Month	31	28	31	30	31	30	31	31	30	31	30	31			
1	10-Residential	83,810	75,699	83,810	81,106	83,810	81,106	82,413	83,810	81,106	83,810	81,106	83,810	985,394	573,149	412,244
2	11-Residential A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	12-CARES	19,753	17,842	19,753	19,116	19,753	19,116	19,298	19,753	19,116	19,753	19,116	19,753	232,122	96,217	135,905
4	13-CARES Med Life Support	15	13	15	14	15	14	15	14	14	15	14	15	172	71	101
5	20-Sm Vol Commercial	52,319	47,256	52,319	50,631	52,319	50,631	51,854	52,319	50,631	52,319	50,631	52,319	615,548	357,794	257,755
6	21-Sm Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	22-Lg Vol Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	T1-Lg Vol Commercial Trans	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	30-Sm Vol Industrial	81	73	81	78	81	78	81	70	78	81	78	81	943	555	389
11	31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	32-Lg Vol Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	40-Sm Vol Pub Auth	5,741	5,186	5,741	5,556	5,741	5,556	5,300	5,741	5,556	5,741	5,556	5,741	67,160	39,264	27,896
16	41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	42-Lg Vol Pub Auth	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	44-Gas Light Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	60-Irrigation Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Total	161,719	146,069	161,719	156,502	161,719	156,502	158,962	161,707	156,502	161,719	156,502	161,719	1,901,339	1,067,050	834,289
22	Total Sales	161,719	146,069	161,719	156,502	161,719	156,502	158,962	161,707	156,502	161,719	156,502	161,719	1,901,339	1,067,050	834,289
23	Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Exhibit JLH - 5
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Citizens Communication Company - SCGD
Sales and Demand Model
<u>Calendar Month Remaining Use, Therms</u>

	REMAINING USE SALES, Therms	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TOTAL	WINTER	SUMMER
1	10-Residential	459,445	314,448	234,032	186,839	48,243	2,495	0	1,396	8,749	36,281	137,957	337,486	1,767,372	1,718,450	48,922
2	11-Residential A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	12-CARES	104,010	69,668	50,689	33,672	7,244	1,873	0	455	2,769	11,756	35,557	75,008	392,701	334,933	57,768
4	13-CARES Med Life Support	70	63	39	31	5	2	0	0	1	12	65	72	361	310	51
5	20-Sm Vol Commercial	153,453	96,543	67,323	60,393	11,228	2,367	0	465	9,043	39,059	71,893	109,946	621,713	570,780	50,933
6	21-Sm Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	22-Lg Vol Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	T1-Lg Vol Commercial Trans|	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	30-Sm Vol Industrial	14,804	10,661	7,551	8,323	10,448	5,477	12	0	2,158	4,764	4,831	13,107	82,135	69,726	12,409
11	31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	32-Lg Vol Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	40-Sm Vol Pub Auth	80,058	59,218	34,644	25,616	8,665	3,076	0	441	774	5,224	20,065	48,034	285,815	276,300	9,515
16	41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
17	42-Lg Vol Pub Auth	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	44-Gas Light Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	60-Irrigation Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	Total	811,842	550,602	394,279	314,873	85,833	15,290	12	2,757	23,493	97,095	270,368	583,654	3,150,098	2,970,499	179,599
22	Total Sales	811,842	550,602	394,279	314,873	85,833	15,290	12	2,757	23,493	97,095	270,368	583,654	3,150,098	2,970,499	179,599
23	Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Citizens Communication Company - SCGD
Sales and Demand Model
Design Day Demand, Therms

DESIGN DAY
DEMAND, Therms

	Customer Class	Total Design Day Demand	Total Design Day Base Demand	Total Design Day Remaining Dem	Annual Load Factor
1	10-Residential	31,503	2,704	28,800	24.1%
2	11-Residential A/C	0	0	0	0.0%
3	12-CARES	7,099	637	6,461	24.5%
4	13-CARES Med Life Support	6	0	6	23.6%
5	20-Sm Vol Commercial	11,057	1,688	9,369	30.9%
6	21-Sm Vol Commercial A/C	0	0	0	0.0%
7	22-Lg Vol Commercial	0	0	0	0.0%
8	23-Lg Vol Commercial A/C	0	0	0	0.0%
9	T1-Lg Vol Commercial Transp	0	0	0	0.0%
10	30-Sm Vol Industrial	1,422	3	1,419	15.5%
11	31-Sm Vol Industrial A/C	0	0	0	0.0%
12	32-Lg Vol Industrial	0	0	0	0.0%
13	33-Lg Vol Industrial A/C	0	0	0	0.0%
14	T1-Lg Vol Industrial Transp	0	0	0	0.0%
15	40-Sm Vol Pub Auth	5,204	185	5,019	18.9%
16	41-Sm Vol Pub Auth A/C	0	0	0	0.0%
17	42-Lg Vol Pub Auth	0	0	0	0.0%
18	T1-Lg Vol Pub Auth Transp	0	0	0	0.0%
19	44-Gas Light Service	0	0	0	0.0%
20	60-Irrigation Service	0	0	0	0.0%
21	Total	56,291	5,217	51,074	24.8%
22	Total Sales	56,291	5,217	51,074	24.8%
23	Total Transportation	0	0	0	0.0%

Citizens Communication Company - SCGD
Sales and Demand Model
Computation of Design Day Demand, Therms - Page 1

DEVELOPMENT OF DESIGN DAY DEMAND, Therms

	Customer Class	Jan-01 1	Feb-01 2	Mar-01 3	Apr-01 4	May-01 5	Jun-01 6	Jul-01 7	Aug-01 8	Sep-01 9	Oct-01 10	Nov-01 11	Dec-01 12	Annual Usage	Consumption Summaries 7 Month Winter	5 Month Summer	7 mo. Wtr % of Annual	Design Day Demand
1	10-Residential	543,255	390,147	317,841	267,945	132,053	83,601	82,413	85,206	89,856	120,091	219,063	421,296	2,752,766	2,291,600	461,167	83.25%	31,503
2	11-Residential A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0
3	12-CARES	123,763	87,510	70,442	52,788	26,997	20,989	19,298	20,208	21,885	31,509	54,673	94,761	624,823	431,150	193,673	69.00%	7,099
4	13-CARES Med Life Support	85	76	54	45	20	16	15	14	15	27	80	86	533	381	152	71.46%	6
5	20-Sm Vol Commercial	205,772	143,799	119,642	111,024	63,547	52,998	51,854	52,783	59,674	91,378	122,524	162,265	1,237,262	928,574	308,688	75.05%	11,057
6	21-Sm Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0
7	22-Lg Vol Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0
8	23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0
9	T1-Lg Vol Commercial Trans|	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0
10	30-Sm Vol Industrial	14,885	10,734	7,632	8,402	10,529	5,555	93	70	2,236	4,845	4,909	13,188	83,078	70,280	12,798	84.60%	1,422
11	31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0
12	32-Lg Vol Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0
13	33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0
14	T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0
15	40-Sm Vol Pub Auth	85,800	64,404	40,386	31,172	14,406	8,633	5,300	6,182	6,330	10,965	25,621	53,775	352,975	315,564	37,411	89.40%	5,204
16	41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0
17	42-Lg Vol Pub Auth	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0
18	T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0
19	44-Gas Light Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0
20	60-Irrigation Service	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0
21	Total	973,561	696,671	555,998	471,375	247,552	171,792	158,973	164,464	179,995	258,814	426,870	745,373	5,051,437	4,037,549	1,013,888	79.93%	56,291
22	Total Sales	973,561	696,671	555,998	471,375	247,552	171,792	158,973	164,464	179,995	258,814	426,870	745,373	5,051,437	4,037,549	1,013,888	79.93%	56,291
23	Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%	0

Citizens Communication Company - SCGD
Sales and Demand Model
Computation of Design Day Demand, Therms - Page 2

	Customer Class	Normal Degree Days in Calendar Month Jan-01 1	Feb-01 2	Mar-01 3	Apr-01 4	May-01 5	Jun-01 6	Jul-01 7	Aug-01 8	Sep-01 9	Oct-01 10	Nov-01 11	Dec-01 12	Total Yr's DD's
1	10-Residential	511	404	307	177	24	2	0	0	2	78	316	515	2,336
2	11-Residential A/C	511	404	307	177	24	2	0	0	2	78	316	515	2,336
3	12-CARES	511	404	307	177	24	2	0	0	2	78	316	515	2,336
4	13-CARES Med Life Support	511	404	307	177	24	2	0	0	2	78	316	515	2,336
5	20-Sm Vol Commercial	511	404	307	177	24	2	0	0	2	78	316	515	2,336
6	21-Sm Vol Commercial A/C	511	404	307	177	24	2	0	0	2	78	316	515	2,336
7	22-Lg Vol Commercial	511	404	307	177	24	2	0	0	2	78	316	515	2,336
8	23-Lg Vol Commercial A/C	511	404	307	177	24	2	0	0	2	78	316	515	2,336
9	T1-Lg Vol Commercial Trans;	511	404	307	177	24	2	0	0	2	78	316	515	2,336
10	30-Sm Vol Industrial	511	404	307	177	24	2	0	0	2	78	316	515	2,336
11	31-Sm Vol Industrial A/C	511	404	307	177	24	2	0	0	2	78	316	515	2,336
12	32-Lg Vol Industrial	511	404	307	177	24	2	0	0	2	78	316	515	2,336
13	33-Lg Vol Industrial A/C	511	404	307	177	24	2	0	0	2	78	316	515	2,336
14	T1-Lg Vol Industrial Transp	511	404	307	177	24	2	0	0	2	78	316	515	2,336
15	40-Sm Vol Pub Auth	511	404	307	177	24	2	0	0	2	78	316	515	2,336
16	41-Sm Vol Pub Auth A/C	511	404	307	177	24	2	0	0	2	78	316	515	2,336
17	42-Lg Vol Pub Auth	511	404	307	177	24	2	0	0	2	78	316	515	2,336
18	T1-Lg Vol Pub Auth Transp	511	404	307	177	24	2	0	0	2	78	316	515	2,336
19	44-Gas Light Service	511	404	307	177	24	2	0	0	2	78	316	515	2,336
20	60-Irrigation Service	511	404	307	177	24	2	0	0	2	78	316	515	2,336
21	Total													
22	Total Sales													
23	Total Transportation													

Citizens Communication Company - SCGD
Sales and Demand Model
Computation of Design Day Demand, Therms - Page 3

	Customer Class	Use Per Customer Jan-01 1	Feb-01 2	Mar-01 3	Apr-01 4	May-01 5	Jun-01 6	Jul-01 7	Aug-01 8	Sep-01 9	Oct-01 10	Nov-01 11	Dec-01 12	Total Yr's
1	10-Residential	107	77	63	53	26	16	16	17	18	24	43	83	542
2	11-Residential A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
3	12-CARES	90	64	51	39	20	15	14	15	16	23	40	69	456
4	13-CARES Med Life Support	85	76	54	45	20	16	15	14	15	27	80	86	533
5	20-Sm Vol Commercial	378	264	220	204	117	97	95	97	110	168	225	298	2,274
6	21-Sm Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
7	22-Lg Vol Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0
8	23-Lg Vol Commercial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
9	T1-Lg Vol Commercial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
10	*30-Sm Vol Industrial*	*4,962*	*3,578*	*2,544*	*2,801*	*3,510*	*1,852*	31	23	745	1,615	1,636	4,396	27,693
11	31-Sm Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
12	32-Lg Vol Industrial	0	0	0	0	0	0	0	0	0	0	0	0	0
13	33-Lg Vol Industrial A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
14	T1-Lg Vol Industrial Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
15	40-Sm Vol Pub Auth	1,300	976	612	472	218	131	80	94	96	166	388	815	5,348
16	41-Sm Vol Pub Auth A/C	0	0	0	0	0	0	0	0	0	0	0	0	0
17	42-Lg Vol Pub Auth	0	0	0	0	0	0	0	0	0	0	0	0	0
18	T1-Lg Vol Pub Auth Transp	0	0	0	0	0	0	0	0	0	0	0	0	0
19	44-Gas Light Service	0	0	0	0	0	0	0	0	0	0	0	0	0
20	60-Irrigation Service	0	0	0	0	0	0	0	0	0	0	0	0	0

Citizens Communication Company - SCGD
Sales and Demand Model
Computation of Design Day Demand, Therms - Page 4

	Customer Class	Monthly Base Use per customer	Regression Prediction: Use per Deg Day per customer	Regression Prediction: R -Square	Load at 39.0	Conventional Weather Norm: Monthly Base Use	Conventional Weather Norm: Use per Deg Day	Conventional Weather Norm: Load at 39.0	Use in Wtr Peak Mo	Peak Month Adjustment: DD In Peak Mo.	Peak Month Adjustment: Use per Deg Day 60%	Load at 39.0	Design Day Load Estimate 90%	Adjusted to Sales System Total 56,291
1	10-Residential	17	0.14	92%	31,514	83,810	774	32,906	390,147	404	736	31,739	31,514	31,503
2	11-Residential A/C	0	0.00	#DIV/0!	0	0	0	0	0	404	0	0	0	0
3	12-CARES	15	0.12	94%	7,101	19,753	172	7,341	87,510	404	165	7,129	7,101	7,099
4	13-CARES Med Life Support	16	0.14	96%	6	15	0	7	76	404	0	6	6	6
5	20-Sm Vol Commercial	105	0.43	94%	11,061	52,319	270	12,223	143,799	404	235	10,780	11,061	11,057
6	21-Sm Vol Commercial A/C	0	0.00	#DIV/0!	0	0	0	0	0	404	0	0	0	0
7	22-Lg Vol Commercial	0	0.00	#DIV/0!	0	0	0	0	0	404	0	0	0	0
8	23-Lg Vol Commercial A/C	0	0.00	#DIV/0!	0	0	0	0	0	404	0	0	0	0
9	T1-Lg Vol Commercial Trans|	0	0.00	#DIV/0!	0	0	0	0	0	404	0	0	0	0
10	30-Sm Vol Industrial	1,114	6.13	61%	827	81	36	1,422	10,734	404	18	826	1,422	1,422
11	31-Sm Vol Industrial A/C	0	0.00	#DIV/0!	0	0	0	0	0	404	0	0	0	0
12	32-Lg Vol Industrial	0	0.00	#DIV/0!	0	0	0	0	0	404	0	0	0	0
13	33-Lg Vol Industrial A/C	0	0.00	#DIV/0!	0	0	0	0	0	404	0	0	0	0
14	T1-Lg Vol Industrial Transp	0	0.00	#DIV/0!	0	0	0	0	0	404	0	0	0	0
15	40-Sm Vol Pub Auth	91	1.82	87%	4,883	5,741	126	5,096	64,404	404	120	5,206	5,206	5,204
16	41-Sm Vol Pub Auth A/C	0	0.00	#DIV/0!	0	0	0	0	0	404	0	0	0	0
17	42-Lg Vol Pub Auth	0	0.00	#DIV/0!	0	0	0	0	0	404	0	0	0	0
18	T1-Lg Vol Pub Auth Transp	0	0.00	#DIV/0!	0	0	0	0	0	404	0	0	0	0
19	44-Gas Light Service	0	0.00	#DIV/0!	0	0	0	0	0	404	0	0	0	0
20	60-Irrigation Service	0	0.00	#DIV/0!	0	0	0	0	0	404	0	0	0	0
21	Total	1,358			55,392	161,719		58,995	696,671			55,685	56,310	56,291
22	Total Sales	1,358			55,392	161,719		58,995	696,671			55,685	56,310	56,291
23	Total Transportation	0			0	0		0	0			0	0	0

Citizens Communication Company - SCGD
Sales and Demand Model
<u>Proportional Responsibility Allocator</u>

DEVELOPMENT OF PR ALLOCATOR

	DATE	Tot Cal Month Sales 1	Ranking 2	Percent of Peak Month 3	Next Ranked Month 4	Next Ranked Month Percent of Peak Month 5	Difference 6	Individual Weighting Factors 7		Cumulative Weighting Factors 8
1	Jan-01	973,561	1	100.0000%	2	76.5615%	23.4385%	23.4385%		39.3340%
2	Feb-01	696,671	3	71.5591%	4	57.1097%	14.4494%	4.8165%		13.3943%
3	Mar-01	555,998	4	57.1097%	5	48.4177%	8.6920%	2.1730%		8.5779%
4	Apr-01	471,375	5	48.4177%	6	43.8462%	4.5714%	0.9143%		6.4048%
5	May-01	247,552	8	25.4275%	9	18.4884%	6.9391%	0.8674%		2.4483%
6	Jun-01	171,792	10	17.6457%	11	16.8931%	0.7527%	0.0753%		1.4873%
7	Jul-01	158,973	12	16.3291%		0.0000%	16.3291%	1.3608%		1.3608%
8	Aug-01	164,464	11	16.8931%	12	16.3291%	0.5640%	0.0513%		1.4120%
9	Sep-01	179,995	9	18.4884%	10	17.6457%	0.8426%	0.0936%		1.5809%
10	Oct-01	258,814	7	26.5843%	8	25.4275%	1.1568%	0.1653%		2.6136%
11	Nov-01	426,870	6	43.8462%	7	26.5843%	17.2619%	2.8770%		5.4906%
12	Dec-01	745,373	2	76.5615%	3	71.5591%	5.0024%	2.5012%		15.8955%
	TOTAL	5,051,437								100.0000%
									WINTER	91.5454%
									SUMMER	8.4546%
										100.0000%

Exhibit JLH - 5
Page ___ of ___

Citizens Communication Company - SCGD
Sales and Demand Model
PR Allocator Weighted By Class Normalized Calendar Month Sales

	PR Monthly Weighting	Jan-01 39.33%	Feb-01 13.39%	Mar-01 8.58%	Apr-01 6.40%	May-01 2.45%	Jun-01 1.49%	Jul-01 1.36%	Aug-01 1.41%	Sep-01 1.58%	Oct-01 2.61%	Nov-01 5.49%	Dec-01 15.90%	TOTAL	ALLOCATION FACTOR
1	10-Residential	213,684	52,257	27,264	17,161	3,233	1,243	1,121	1,203	1,421	3,139	12,028	66,967	400,722	55.75%
2	11-Residential A/C	-	-	-	-	-	-	-	-	-	-	-	-	0	0.00%
3	12-CARES	48,681	11,721	6,042	3,381	661	312	263	285	346	824	3,002	15,063	90,581	12.60%
4	13-CARES Med Life Support	33	10	5	3	0	0	0	0	0	1	4	14	71	0.01%
5	20-Sm Vol Commercial	80,939	19,261	10,263	7,111	1,556	788	706	745	943	2,388	6,727	25,793	157,220	21.87%
6	21-Sm Vol Commercial A/C	-	-	-	-	-	-	-	-	-	-	-	-	0	0.00%
7	22-Lg Vol Commercial	-	-	-	-	-	-	-	-	-	-	-	-	0	0.00%
8	23-Lg Vol Commercial A/C	-	-	-	-	-	-	-	-	-	-	-	-	0	0.00%
9	T1-Lg Vol Commercial Trans|	-	-	-	-	-	-	-	-	-	-	-	-	0	0.00%
10	30-Sm Vol Industrial	5,855	1,438	655	538	258	83	1	1	35	127	270	2,096	11,356	1.58%
11	31-Sm Vol Industrial A/C	-	-	-	-	-	-	-	-	-	-	-	-	0	0.00%
12	32-Lg Vol Industrial	-	-	-	-	-	-	-	-	-	-	-	-	0	0.00%
13	33-Lg Vol Industrial A/C	-	-	-	-	-	-	-	-	-	-	-	-	0	0.00%
14	T1-Lg Vol Industrial Transp	-	-	-	-	-	-	-	-	-	-	-	-	0	0.00%
15	40-Sm Vol Pub Auth	33,749	8,627	3,464	1,997	353	128	72	87	100	287	1,407	8,548	58,818	8.18%
16	41-Sm Vol Pub Auth A/C	-	-	-	-	-	-	-	-	-	-	-	-	0	0.00%
17	42-Lg Vol Pub Auth	-	-	-	-	-	-	-	-	-	-	-	-	0	0.00%
18	T1-Lg Vol Pub Auth Transp	-	-	-	-	-	-	-	-	-	-	-	-	0	0.00%
19	44-Gas Light Service	-	-	-	-	-	-	-	-	-	-	-	-	0	0.00%
20	60-Irrigation Service	-	-	-	-	-	-	-	-	-	-	-	-	0	0.00%
21	Total	382,941	93,314	47,693	30,191	6,061	2,555	2,163	2,322	2,846	6,764	23,438	118,481	718,768	100.00%
22	Total Sales	382,941	93,314	47,693	30,191	6,061	2,555	2,163	2,322	2,846	6,764	23,438	118,481	718,768	100.00%
23	Total Transportation	0	0	0	0	0	0	0	0	0	0	0	0	0	0.00%

Citizens Communications
Arizona Gas Division
Allocation Factor Description

DEMGAS	Production capacity cost allocator based on class design day demand. Reference JLH-5 pages 46 through 49 (NAGD) and pages 56 through 59 (SCGD).
TRANS	Transmission allocation factor based on Proportional Responsibility. Reference JLH-5 pages 50 through 51 (NAGD) and pages 60 through 61 (SCGD). Also, refer to JLH-11 pages 272 through 290.
DISTR	Distribution allocation factor based on Proportional Responsibility. Reference JLH-5 pages 50 through 51 (NAGD) and pages 60 through 61 (SCGD). Also, refer to JLH-11 pages 272 through 290.
DISTMAN	Distribution mains allocation factor based on Proportional Responsibility. Reference JLH-5 pages 50 through 51 (NAGD) and pages 60 through 61 (SCGD). Also, refer to JLH-11 pages 272 through 290.
DISTREG	Distribution regulator allocation factor based on Proportional Responsibility. Reference JLH-5 pages 50 through 51 (NAGD) and pages 60 through 61 (SCGD). Also, refer to JLH-11 pages 272 through 290.
GASSALES	Production commodity cost allocator based on rate class monthly sales volumes weighted by the monthly cost of gas. Reference JLH-5 page 33 (NAGD) and page 38 (SCGD).
THERMS	Annual firm therm throughput.
CARES	Annual firm therm throughput excluding C.A.R.E.S. customers.
CUST10	Year end number of customers.
CUST380	Assignment of services investment in account 380. Reference JLH-11 pages 291 through 296. Historic plant investment was prorated to rate classes on the basis of each class's year-end number of customers weighted by the average service cost for each class.
CUST381	Assignment of meter investment in account 381. Reference JLH-11 pages 297 through 307. Meter replacement cost times year-end number of customers.
CUST382	Assignment of meter installations in account 382. Same as CUST381.
CUST383	Assignment of house regulators in account 383. Same as CUST381.

Citizens Communications
Arizona Gas Division
Allocation Factor Description

CUST384	Assignment of house regulator installations in account 384. Same as CUST381.
CUST385	Assignment of Industrial meter and regulator investment in account 385. Reference JLH-11 pages 297 through 307. Meter replacement cost times year-end number of customers.
CUSTDEP	Assignment of Customer Deposits. Historic deposits by major customer class (reference JLH-11 page 318) was prorated to rate classes on basis of year-end number of customers.
CUSTADV	Assignment of Customer Advances for Construction. This allocation factor identifies the year-end number of customers by class of service, but was not used. The allocation of Customer Advances for Construction on Schedule G-3 was performed using an internally developed allocation factor labeled PLT376380 which is the sum of allocated Mains (Acct 376) and Services (Acct 380).
CONTSERV	Assignment of Contributions in Aid of Construction - Services. This allocation factor identifies the year-end number of customers by class of service, but was not used. The allocation of Contributions in Aid of Construction for Services on Schedule G-3 was performed using an internally developed allocation factor based on allocated Services (Acct 380).
CONTMAIN	Assignment of Contributions in Aid of Construction - Mains. This allocation factor identifies the year-end number of customers by class of service, but was not used. The allocation of Contributions in Aid of Construction for Mains on Schedule G-3 was performed using an internally developed allocation factor based on allocated Mains (Acct 376).
CUST487B	Assignment of Miscellaneous Service Revenue in account 487. Directly assigned based on the reported revenues shown on Exhibit JLH-11, pages 319 through 328.
CUST902	Assignment of Meter Reading Expenses in account 902. Year-end number of customers weighted by meter read times shown in Exhibit JLH-1, pages 308 and 309.
CUST903	Assignment of Customer Records and Collection Expenses in account 903. The allocation factor was developed by assigning the expenses provided on Exhibit JLH-11, pages 310 and 311, to classes on the basis of year-end number of customer. This calculation is provided in Exhibit JLH-5.

Citizens Communications
Arizona Gas Division
Allocation Factor Description

CDA912	Assignment of Demo and Selling Expenses in account 912. Year-end number of customers.
CDA913	Assignment of Advertising Expenses in account 913. Year-end number of customers.

6

CITIZENS COMMUNICATIONS COMPANY
COMBINED ARIZONA GAS DIVISIONS
TWELVE MONTHS ENDED DECEMBER 31, 2001
DEVELOPMENT OF COMBINED NAGD & SCGD REVENUE TARGET

LINE NO.	CLASS/RATE	TOTAL ADJUSTED PRESENT	LESS ADJ. PGA REVENUE	LESS ADJ. COST OF GAS	PRESENT ADJ. BASE REVENUE	COST OF SERVICE	LESS ALLOCATED FUEL	COSS BASE	THERMS
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	RESIDENTIAL								
2	Residential Service	$47,934,081	$12,065,089	$16,948,610	$18,920,383	$63,020,145	$29,447,657	$33,572,488	66,270,508
3	Residential Service Air Conditioning	2,616	652	966	999	3,408	1,690	1,718	3,863
4	C.A.R.E.S.	1,156,313	209,205	458,770	488,338	1,545,902	672,892	873,010	1,489,179
5	C.A.R.E.S. Medical Life Support	1,000	207	395	399	1,247	588	660	1,284
6	Total Residential	$49,094,011	$12,275,152	$17,408,741	$19,410,118	$64,570,702	$30,122,827	$34,447,875	67,764,834
7									
8	COMMERCIAL								
9	Small Volume Commercial	$17,082,000	$5,199,834	$7,276,269	$4,605,896	$19,065,514	$12,134,019	$6,931,495	28,420,129
10	Small Volume Commercial Air Conditioning	15,105	4,943	6,695	3,467	14,934	10,627	4,307	26,781
11	Large Volume Commercial Incl T-1	1,261,644	378,307	479,051	404,285	1,488,555	816,579	671,977	4,150,550
12	Large Volume Commercial Air Conditioning	0	0	0	0	0	0	0	0
13	Total Commercial	$18,358,749	$5,583,084	$7,762,016	$5,013,649	$20,569,003	$12,961,224	$7,607,779	32,597,460
14									
15	INDUSTRIAL								
16	Small Volume Industrial	$519,486	$172,530	$259,687	$87,269	$573,587	$416,363	$157,223	992,756
17	Small Volume Industrial Air Conditioning	0	0	0	0	0	0	0	0
18	Large Volume Industrial Incl T-1	2,144,635	572,010	728,866	843,759	3,391,285	1,200,855	2,190,430	17,151,929
19	Large Volume Industrial T-2	0	0	0	0	62,711	0	62,711	0
20	Total Industrial	$2,664,121	$744,540	$988,553	$931,028	$4,027,582	$1,617,218	$2,410,364	18,144,685
21									
22	Public Authority								
23	Small Volume Public Authority	$3,217,174	$1,001,291	$1,446,234	$769,649	$3,874,707	$2,518,629	$1,356,078	5,589,530
24	Small Volume Public Authority Air Conditioning	0	0	0	0	0	0	0	0
25	Large Volume Public Authority Incl T-1	947,159	212,188	276,018	458,952	1,539,798	490,018	1,049,780	6,542,207
26	Large Volume Public Authority Air Conditioning	0	0	0	0	0	0	0	0
27	Total Public Authority	$4,164,333	$1,213,479	$1,722,253	$1,228,601	$5,414,505	$3,008,648	$2,405,857	12,131,738
28									
29	Special Gas Light Service	$67,246	$19,790	$26,549	$20,908	$77,861	$41,394	$36,467	106,194
30									
31	Irrigation	$95,664	$36,205	$48,061	$11,397	$82,677	$70,388	$12,289	192,245
32									
33	Cogenration Rate	$0	$0	$0	$0	$0	$0	$0	0
34									
35	Grand Total	$74,444,123	$19,872,250	$27,956,171	$26,615,701	$94,742,331	$47,821,700	$46,920,631	130,937,155

CITIZENS COMMUNICATIONS COMPANY
COMBINED ARIZONA GAS DIVISIONS
DEVELOPMENT OF COMBINED NAGD & SCGD REVENUE TARGET

LINE NO.	CLASS/RATE	BASE RATE INCREASE PER COSS, %	CAPPED INCREASE, %	INCREASE LIMITATION CHECK	ALLOCATION OF SUBSIDIES FROM CAP	PRELIMINARY BASE TARGET	BASE RATE PERCENT CHANGE	PLUS ALLOCATED FUEL	LESS PGA	CARES DISCOUNT	CARES ALLOCATION	ADJUSTED BASE TARGET REVENUE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	RESIDENTIAL								0.0386			
2	Residential Service	77.44%	77.44%	$33,572,488	$504,916	$34,077,404	80.11%	$29,447,657	$2,559,213		$74,862	$61,040,711
3	Residential Service Air Conditioning	72.02%	72.02%	$1,718	26	1,744	74.60%	1,690	149		$4	3,289
4	C.A.R.E.S.	78.77%	78.77%	$873,010	13,130	886,139	81.46%	672,892	57,509	147,779	$1,682	1,355,426
5	C.A.R.E.S. Medical Life Support	65.44%	65.44%	$660	10	669	67.93%	588	50	134	$1	1,076
6	Total Residential	77.47%		$34,447,875	$518,082	$34,965,956	80.14%	$30,122,827	$2,616,920	$147,913	$76,550	$62,400,502
7												
8	COMMERCIAL											
9	Small Volume Commercial	50.49%	50.49%	$6,931,495	$104,247	$7,035,742	52.76%	$12,134,019	$1,097,519		$32,105	$18,104,347
10	Small Volume Commercial Air Conditioning	24.25%	24.25%	$4,307	65	4,372	26.12%	10,627	1,034		$30	13,995
11	Large Volume Commercial Incl T-1	66.21%	66.21%	$671,977	10,106	682,083	68.71%	816,579	73,999		$4,689	1,429,351
12	Large Volume Commercial Air Conditioning	0.00%	0.00%	$0	0	0	0.00%	0	0		$0	0
13	Total Commercial	51.74%		$7,607,779	$114,418	$7,722,197	54.02%	$12,961,224	$1,172,553	$0	$36,824	$19,547,692
14												
15	INDUSTRIAL											
16	Small Volume Industrial	80.16%	80.16%	$157,223	$2,365	$159,588	82.87%	$416,363	$38,338		$1,121	$538,735
17	Small Volume Industrial Air Conditioning	0.00%	0.00%	$0	0	0	0.00%	0	0		$0	0
18	Large Volume Industrial Incl T-1	159.60%	Cap @ 95.36%	$1,648,382	24,791	1,673,173	98.30%	1,200,855	112,588		$19,376	2,780,815
19	Large Volume Industrial T-2	0.00%	0.00%	$62,711	943	63,654	0.00%	0	0		$0	63,654
20	Total Industrial	158.89%		$1,868,316	$28,099	$1,896,415	103.69%	$1,617,218	$150,926	$0	$20,497	$3,383,204
21												
22	Public Authority											
23	Small Volume Public Authority	76.19%	76.19%	$1,356,078	$20,395	$1,376,472	78.84%	$2,518,629	$215,855		$6,314	$3,685,561
24	Small Volume Public Authority Air Conditioning	0.00%	0.00%	$0	0	0	0.00%	0	0		$0	0
25	Large Volume Public Authority Incl T-1	128.73%	Cap @ 95.36%	$896,616	13,485	910,101	98.30%	490,018	42,637		$7,390	1,364,873
26	Large Volume Public Authority Air Conditioning	0.00%	0.00%	$0	0	0	0.00%	0	0		$0	0
27	Total Public Authority	95.82%		$2,252,694	$33,880	$2,286,574	86.11%	$3,008,648	$258,491	$0	$13,705	$5,050,434
28												
29	Special Gas Light Service	74.42%	74.42%	$36,467	$548	$37,015	77.04%	$41,394	$4,101	$0	$120	$74,429
30												
31	Irrigation	7.82%	7.82%	$12,289	$185	$12,473	9.44%	$70,388	$7,424	$0	$217	$75,655
32												
33	Cogenration Rate	0.00%	0.00%	$0	$0	$0	0.00%	$0	$0	$0	$0	$0
34												
35	Grand Total	76.29%		$46,225,420	$695,211	$46,920,631	76.29%	$47,821,700	$4,210,415	$147,913	$147,913	$90,531,915

1.25 Times System Average =	95.36%		
Shortfall		$695,211	$0

CITIZENS COMMUNICATIONS COMPANY
COMBINED ARIZONA GAS DIVISIONS
DEVELOPMENT OF COMBINED NAGD & SCGD REVENUE TARGET

LINE NO.	CLASS/RATE	TOTAL REVENUE TARGET	BASE RATE BOOKED TO BILLED ADJ.	RATE DESIGN TARGET		BILLED BASE RATE RECOVERY	EXPECTED BOOKED REVENUE	DEVIATION FROM TARGET
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	RESIDENTIAL							
2	Residential Service	$61,040,711	0.99334	$61,450,047		$61,497,599	$61,087,946	$47,235
3	Residential Service Air Conditioning	3,289	0.99650	3,300		3,443	3,431	142
4	C.A.R.E.S.	1,355,426	1.00223	1,352,414		1,298,671	1,301,564	(53,862)
5	C.A.R.E.S. Medical Life Support	1,076	1.00501	1,070		1,051	1,057	(19)
6	Total Residential	$62,400,502		$62,806,831		$62,800,765	$62,393,998	($6,503)
7								
8	COMMERCIAL							
9	Small Volume Commercial	$18,104,347	0.99093	$18,270,032		$18,266,703	$18,101,048	($3,299)
10	Small Volume Commercial Air Conditioning	13,995	1.00002	13,995		16,358	16,358	2,363
11	Large Volume Commercial Incl T-1	1,429,351	0.99913	1,430,600		1,430,430	1,429,193	(158)
12	Large Volume Commercial Air Conditioning	0	1.00000	0		0	0	0
13	Total Commercial	$19,547,692		$19,714,627		$19,713,490	$19,546,598	($1,094)
14								
15	INDUSTRIAL							
16	Small Volume Industrial	$538,735	0.95868	$561,956		$561,935	$538,715	($20)
17	Small Volume Industrial Air Conditioning	0	1.00000	0		0	0	0
18	Large Volume Industrial Incl T-1	2,780,815	0.96965	2,867,848		2,877,602	2,786,787	5,973
19	Large Volume Industrial T-2	63,654	1.00000	63,654		62,815	62,815	(840)
20	Total Industrial	$3,383,204		$3,493,458		$3,502,352	$3,388,317	$5,113
21								
22	Public Authority							
23	Small Volume Public Authority	$3,685,561	0.99113	$3,718,560		$3,718,784	$3,685,784	$222
24	Small Volume Public Authority Air Conditioning	0	1.00000	0		0	0	0
25	Large Volume Public Authority Incl T-1	1,364,873	0.99339	1,373,959		1,373,867	1,364,677	(196)
26	Large Volume Public Authority Air Conditioning	0	1.00000	0		0	0	0
27	Total Public Authority	$5,050,434		$5,092,519		$5,092,651	$5,050,461	$26
28								
29	Special Gas Light Service	$74,429	0.99876	$74,521		$74,502	$74,410	($19)
30								
31	Irrigation	$75,655	0.80674	$93,778		$93,773	$75,651	($4)
32								
33	Cogenration Rate	$0	0.00000	$0		$0	$0	$0
34								
35	Grand Total	$90,531,915		$91,275,735		$91,277,534	$90,529,435	($2,480)

CITIZENS COMMUNICATIONS COMPANY
COMBINED ARIZONA GAS DIVISIONS
DEVELOPMENT OF COMBINED NAGD & SCGD REVENUE TARGET

LINE NO.	CLASS/RATE	TOTAL ADJUSTED PRESENT	PROPOSED REVENUE	CHANGE	PERCENT CHANGE
	(1)	(2)	(3)	(4)	(5)
1	RESIDENTIAL				
2	Residential Service (10)	$47,934,081	$63,647,159	$15,713,077	32.78%
4	Residential Service Air Conditioning (11)	2,616	3,580	964	36.85%
6	C.A.R.E.S. (12)	1,156,313	1,359,073	202,760	17.54%
8	C.A.R.E.S. Medical Life Support (13)	1,000	1,106	106	10.63%
9	Total Residential	$49,094,011	$65,010,918	$15,916,908	32.42%
10					
11	COMMERCIAL				
12	Small Volume Commercial (20)	$17,082,000	$19,198,567	$2,116,567	12.39%
14	Small Volume Commercial Air Conditioning (21)	15,105	17,392	2,287	15.14%
15	Large Volume Commercial (22) Incl T-1	1,261,644	1,503,192	241,548	19.15%
16	Large Volume Commercial Air Conditioning (23)	0	0	0	0.00%
17	Total Commercial	$18,358,749	$20,719,151	$2,360,402	12.86%
18					
19	INDUSTRIAL				
20	Small Volume Industrial (30)	$519,486	$577,053	$57,567	11.08%
21	Small Volume Industrial Air Conditioning (31)	0	0	0	0.00%
22	Large Volume Industrial (32) Incl T-1	2,144,635	2,899,377	754,742	35.19%
23	Large Volume Industrial T-2	0	62,815	62,815	0.00%
24	Total Industrial	$2,664,121	$3,539,245	$875,124	32.85%
25					
26	Public Authority				
27	Small Volume Public Authority (40)	$3,217,174	$3,901,638	$684,464	21.28%
29	Small Volume Public Authority Air Conditioning (41)	0	0	0	0.00%
30	Large Volume Public Authority (42) Incl T-1	947,159	1,407,314	460,155	48.58%
31	Large Volume Public Authority Air Conditioning (43)	0	0	0	0.00%
32	Total Public Authority	$4,164,333	$5,308,952	$1,144,619	27.49%
33					
34	Special Gas Light Service (44)	$67,246	$78,511	$11,265	16.75%
35					
36	Irrigation (60)	$95,664	$83,075	($12,589)	-13.16%
37					
38	Cogenration Rate	$0	$0	$0	0.00%
39					
46	Grand Total	$74,444,123	$94,739,852	$20,295,729	27.26%

Deviation from Cost of Service	($2,479)		
		1.25 Limitation	34.08%

CITIZENS COMMUNICATIONS
NORTHERN ARIZONA GAS DIVISION
TWELVE MONTHS ENDED DECEMBER 31, 2001
COMBINED NAGD & SCGD RATE DESIGN

Line No.	Description	Billing Units	Calculated Rate	Proposed Rate	Proposed Revenue	Booked to Billed Ratio	Booked Proposed Revenue
1	RESIDENTIAL SERVICE						
2	Number of Bills	1,272,251	$10.00	$10.00	$12,722,505.29		
3	Base Cost	66,270,508	0.7360	0.7360	48,775,093.63		
4	Subtotal Basic Service				$61,497,598.92	0.99334	$61,087,946.18
5	Purchased Gas Adjustment	66,270,508	0.0386	0.0386	2,559,212.57	1.00000	2,559,212.57
6	Total Residential				$64,056,811.49	0.99360	$63,647,158.75
7							
8	RESIDENTIAL SERVICE AIR CONDITIONING						
9	Number of Bills	60	$10.00	$10.00	$600.00		
10	Base Cost						
11	First 25 therms	1,041	0.7360	0.7360	766.02		
12	All Over 25 therms						
13	June - Oct.	463	0.7360	0.7360	340.64		
14	Nov. - May	2,360	0.7360	0.7360	1,736.66		
15	Subtotal Basic Service				$3,443.32	0.99650	$3,431.27
16	Purchased Gas Adjustment	3,863	0.0386	0.0386	149.19	1.00001	149.19
17	Total Residential Air Conditioning				$3,592.51	0.99665	$3,580.46
18							
19	C.A.R.E.S						
20	Number of Bills	35,041	$10.00	$10.00	$350,414.71		
21	Base Cost						
22	First 100 therms						
23	May. - Oct.	311,517	0.7360	0.7360	229,276.50		
24	Nov. - Apr.	985,194	0.5860	0.5860	577,323.71		
25	All Over 100 therms	192,468	0.7360	0.7360	141,656.37		
26	Subtotal Basic Service				$1,298,671.29	1.00223	$1,301,564.13
27	Purchased Gas Adjustment	1,489,179	0.0386	0.0386	57,508.62	1.00000	57,508.62
28	Total C.A.R.E.S.				$1,356,179.91	1.00213	$1,359,072.75
29							
30	C.A.R.E.S. MEDICAL LIFE SUPPORT						
31	Number of Bills	24	$10.00	$10.00	$240.00		
32	Base Cost						
33	First 100 therms						
34	May. - Oct.	284	0.7360	0.7360	208.69		
35	Nov. - Apr.	891	0.5860	0.5860	522.02		
36	All Over 100 therms	110	0.7360	0.7360	80.72		
37	Subtotal Basic Service				$1,051.43	1.00501	$1,056.70
38	Purchased Gas Adjustment	1,284	0.0386	0.0386	49.59	1.00001	49.59
39	Total C.A.R.E.S. Medical Life Support				$1,101.02	1.00479	$1,106.29

CITIZENS COMMUNICATIONS
NORTHERN ARIZONA GAS DIVISION
TWELVE MONTHS ENDED DECEMBER 31, 2001
COMBINED NAGD & SCGD RATE DESIGN

Line No.	Description	Billing Units	Calculated Rate	Proposed Rate	Proposed Revenue	Booked to Billed Ratio	Booked Proposed Revenue
1	SMALL VOLUME COMMERCIAL SERVICE						
2	Number of Bills	120,760	$13.00	13.00	$1,569,877.10		
3	Base Cost	28,420,129	0.5875	0.5875	16,696,825.83		
4	Subtotal Basic Service				$18,266,702.93	0.99093	$18,101,047.77
5	Purchased Gas Adjustment	28,420,129	0.0386	0.0386	1,097,519.16	1.00000	1,097,519.16
6	Total Sm. Vol. Commercial				$19,364,222.09	0.99145	$19,198,566.93
7							
8							
9	SMALL VOLUME COMMERCIAL AIR CONDITIONING SERVICE						
10	Number of Bills	48	$13.00	$13.00	$624.00		
11	Base Cost						
12	First 250 therms	9,651	0.5875	0.5875	5,670.16		
13	All Over 250 therms						
14	June - Oct.	8,395	0.5875	0.5875	4,931.92		
15	Nov. - May	8,735	0.5875	0.5875	5,131.64		
16	Subtotal Basic Service				$16,357.72	1.00002	$16,358.05
17	Purchased Gas Adjustment	26,781	0.0386	0.0386	1,034.21	1.00000	1,034.21
18	Total Sm. Vol. Commercial Air Conditioning				$17,391.93	1.00002	$17,392.26
19							
20							
21	LARGE VOLUME COMMERCIAL SERVICE						
22	Number of Bills	144	$ 95.00	$95.00	$13,680.00		
23	Base Cost	1,916,206	0.5447	0.5447	1,043,757.17		
24	Subtotal Basic Service				$1,057,437.17	0.99883	$1,056,199.97
25	Purchased Gas Adjustment	1,916,206	0.0386	0.0386	73,999.39	1.00000	73,999.39
26	Total Lg. Vol. Commercial				$1,131,436.56	0.99891	$1,130,199.36
27							
28							
29	LARGE VOLUME COMMERCIAL AIR CONDITIONING SERVICE						
30	Number of Bills	0	$95.00	$95.00	$0.00		
31	Base Cost						
32	All therms						
33	June - Oct.	0	0.5447	0.5447	0.00		
34	Nov. - May	0	0.5447	0.5447	0.00		
35	Subtotal Basic Service				$0.00	0.00000	$0.00
36	Purchased Gas Adjustment	0	0.0386	0.0386	0.00	0.00000	0.00
37	Total Lg. Vol. Commercial Air Conditioning				$0.00	0.00000	$0.00

CITIZENS COMMUNICATIONS
NORTHERN ARIZONA GAS DIVISION
TWELVE MONTHS ENDED DECEMBER 31, 2001
COMBINED NAGD & SCGD RATE DESIGN

Line No.	Description	Billing Units	Calculated Rate	Proposed Rate	Proposed Revenue	Booked to Billed Ratio	Booked Proposed Revenue
1	SMALL VOLUME INDUSTRIAL SERVICE						
2	Number of Bills	232	$13.00	$13.00	$3,013.66		
3	Base Cost	992,756	0.5630	0.5630	558,921.58		
4	Subtotal Basic Service				$561,935.24	0.95868	$538,715.08
5	Purchased Gas Adjustment	992,756	0.0386	0.0386	38,337.92	1.00000	38,337.92
6	Total Sm. Vol. Industrial				$600,273.16	0.96132	$577,053.00
7							
8							
9	SMALL VOLUME INDUSTRIAL AIR CONDITIONING SERVICE						
10	Number of Bills	0	$13.00	$13.00	$0.00		
11	Base Cost						
12	All therms						
13	June - Oct.	0	0.5630	0.5630	0.00		
14	Nov. - May	0	0.5630	0.5630	0.00		
15	Subtotal Basic Service				$0.00	0.00000	$0.00
16	Purchased Gas Adjustment	0	0.0386	0.0386	0.00	0.00000	0.00
17	Total Sm. Vol. Industrial Air Conditioning				$0.00	0.00000	$0.00
18							
19							
20	LARGE VOLUME INDUSTRIAL SERVICE						
21	Number of Bills	108	$ 95.00	$95.00	$10,260.00		
22	Base Cost	2,915,498	0.4831	0.4831	1,408,477.22		
23	Subtotal Basic Service				$1,418,737.22	1.00000	$1,418,737.22
24	Purchased Gas Adjustment	2,915,498	0.0386	0.0386	112,589.75	1.00000	112,589.75
25	Total Lg. Vol. Industrial				$1,531,326.97	1.00000	$1,531,326.97
26							
27							
28	LARGE VOLUME INDUSTRIAL AIR CONDITIONING SERVICE						
29	Number of Bills	0	$95.00	$95.00	$0.00		
30	Base Cost						
31	All therms						
32	June - Oct.	0	0.4831	0.4831	0.00		
33	Nov. - May	0	0.4831	0.4831	0.00		
34	Subtotal Basic Service				$0.00	0.00000	$0.00
35	Purchased Gas Adjustment	0	0.0386	0.0386	0.00	0.00000	0.00
36	Total Lg. Vol. Industrial Air Conditioning				$0.00	0.00000	$0.00

CITIZENS COMMUNICATIONS
NORTHERN ARIZONA GAS DIVISION
TWELVE MONTHS ENDED DECEMBER 31, 2001
COMBINED NAGD & SCGD RATE DESIGN

Line No.	Description	Billing Units	Calculated Rate	Proposed Rate	Proposed Revenue	Booked to Billed Ratio	Booked Proposed Revenue
1	SMALL VOLUME PUBLIC AUTHORITY SERVICE						
2	Number of Bills	11,356	$13.00	$13.00	$147,633.24		
3	Base Cost	5,589,530	0.6389	0.6389	3,571,150.85		
4	Subtotal Basic Service				$3,718,784.09	0.99113	$3,685,783.68
5	Purchased Gas Adjustment	5,589,530	0.0386	0.0386	215,854.63	1.00000	215,854.63
6	Total Sm. Vol. Public Authority				$3,934,638.72	0.99161	$3,901,638.31
7							
8							
9	SMALL VOLUME PUBLIC AUTHORITY AIR CONDITIONING SERVICE						
10	Number of Bills	0	$13.00	$13.00	$0.00		
11	Base Cost						
12	First 250 therms	0	0.6389	0.6389	0.00		
13	All Over 250 therms						
14	June - Oct.	0	0.6389	0.6389	0.00		
15	Nov. - May	0	0.6389	0.6389	0.00		
16	Subtotal Basic Service				$0.00	0.000000	$0.00
17	Purchased Gas Adjustment	0	0.0386	0.0386	0.00	0.000000	0.00
18	Total Sm. Vol. Public Authority Air Conditioning				$0.00	0.00000	$0.00
19							
20							
21	LARGE VOLUME PUBLIC AUTHORITY SERVICE						
22	Number of Bills	60	$ 95.00	$95.00	$5,700.00		
23	Base Cost	1,104,074	0.5533	0.5533	610,883.98		
24	Subtotal Basic Service				$616,583.98	0.98372	$606,545.99
25	Purchased Gas Adjustment	1,104,074	0.0386	0.0386	42,636.75	1.00000	42,636.75
26	Total Lg. Vol. Public Authority				$659,220.73	0.98477	$649,182.74
27							
28							
29	LARGE VOLUME PUBLIC AUTHORITY AIR CONDITIONING SERVICE						
30	Number of Bills	0	$95.00	$95.00	$0.00		
31	Base Cost						
32	All therms						
33	June - Oct.	0	0.5533	0.5533	0.00		
34	Nov. - May	0	0.5533	0.5533	0.00		
35	Subtotal Basic Service				$0.00	0.00000	$0.00
36	Purchased Gas Adjustment	0	0.0386	0.0386	0.00	0.00000	0.00
37	Total Lg. Vol. Public Authority Air Conditioning				$0.00	0.00000	$0.00

CITIZENS COMMUNICATIONS
NORTHERN ARIZONA GAS DIVISION
TWELVE MONTHS ENDED DECEMBER 31, 2001
COMBINED NAGD & SCGD RATE DESIGN

Line No.	Description	Billing Units	Calculated Rate	Proposed Rate	Proposed Revenue	Booked to Billed Ratio	Booked Proposed Revenue
1	SPECIAL GAS LIGHT SERVICE						
2	Base Cost Per Light						
3	Lake Havasu City						
4	Lighting Group A	876	$13.19	$13.19	$11,554.44		
5	Lighting Group B	3,792	15.82	$15.82	59,989.44		
6	Lighting Group C	168	17.61	$17.61	2,958.48		
7	Single Orifice	0	23.06	$23.06	0.00		
8	Double Orifice	0	38.43	$38.43	0.00		
9	Triple Orifice	0	53.32	$53.32	0.00		
10	Quadruple Orifice	0	69.17	$69.17	0.00		
11	Subtotal Basic Service				$74,502.36	0.99876	$74,409.98
12	Purchased Gas Adjustment (22 therms per orifice	106,194	0.0386	0.0386	4,100.96	1.00000	4,100.96
13	Total Special Gas Light Service				$78,603.32	0.99882	$78,510.94
14							
15							
16	IRRIGATION SERVICE						
17	Number of Bills	84	$13.00	$13.00	$1,092.00		
18	Base Cost	192,245	0.4821	0.4821	92,681.24		
19	Subtotal Basic Service				$93,773.24	0.80674	$75,650.62
20	Purchased Gas Adjustment	192,245	0.0386	0.0386	7,424.05	1.00000	7,424.05
21	Total Irrigation Service				$101,197.29	0.82092	$83,074.67
22							
23							
24	ELECTRIC COGENERATION SERVICE						
25	Number of Bills	0	$ 95.00	$95.00	$0.00		
26	Base Cost						
27	All therms						
28	June - Oct.	0	0.4677	0.4677	0.00		
29	Nov. - May	0	0.4677	0.4677	0.00		
30	Subtotal Basic Service				$0.00	1.00000	$0.00
31	Purchased Gas Adjustment	0	0.0386	0.0386	0.00	1.00000	0.00
32	Total Lg. Vol. Public Authority Air Conditioning				$0.00	0.00000	$0.00

CITIZENS COMMUNICATIONS
NORTHERN ARIZONA GAS DIVISION
TWELVE MONTHS ENDED DECEMBER 31, 2001
COMBINED NAGD & SCGD RATE DESIGN

Line No.	Description	Billing Units	Calculated Rate	Proposed Rate	Proposed Revenue	Booked to Billed Ratio	Booked Proposed Revenue
1	TRANSPORTATION - LARGE VOLUME COMMERCIAL SERVICE						
2	Number of Bills	108	$95.00	$95.00	$10,260.00		
3	Sales Volumes						
4	Cost of Service	2,234,344	0.1567	0.1567	350,121.76		
5	Back Up Reservation Fee				12,611		
6	Negotialted Discount Rate		0.0000	0.0000	0		
10	Total Lg. Vol. Commercial T1				$372,992.56	1.00000	$372,992.56
11							
12							
13							
14	TRANSPORTATION - LARGE VOLUME INDUSTRIAL SERVICE						
15	Number of Bills	126	$95.00	$95.00	$11,970.00		
16	Sales Volumes						
17	Cost of Service	14,236,466	0.1098	0.1098	1,563,164.02		
18	Back Up Reservation Fee				16,740		
19	Negotialted Discount Rate		(0.0093)	(0.0093)	(133,010)		
23	Total Lg. Vol. Industrial T1				$1,458,864.50	0.93775	$1,368,050.19
24							
25							
26							
27	TRANSPORTATION - LARGE VOLUME PUBLIC AUTHORITY						
28	Number of Bills	72	$95.00	$95.00	$6,840.00		
29	Sales Volumes						
30	Cost of Service	5,438,134	0.1414	0.1414	768,952.10		
31	Back Up Reservation Fee				0		
32	Negotialted Discount Rate		(0.0034)	(0.0034)	(18,509)		
33	Total Lg. Vol. Public Authority T1				$757,282.88	1.00112	$758,131.04
34							
35	TRANSPORTATION - LARGE INDUSTRIAL - T-2						
36	Number of Bills	36	$100.00	$100.00	$3,600.00		
37							
38	Reservation Fee	36	1,644.86	1,644.86	59,214.80		
39	Back Up Reservation Fee						
40	Negotialted Discount Rate						
41	Total Large Industrial T2				$62,814.80	1.00000	$62,814.80

CITIZENS COMMUNICATIONS
NORTHERN ARIZONA GAS DIVISION
TWELVE MONTHS ENDED DECEMBER 31, 2001
COMBINED NAGD & SCGD RATE DESIGN

RATE DESIGN SUMMARY	Present			Proposed		
	Customer Charge	Base Commodity	Disc Block	Customer Charge	Base Commodity	Disc Block
RESIDENTIAL						
Residential Service (10)	$5.00	0.4414		$10.00	0.7360	
Residential Service Air Conditioning (11)	$5.00	0.4414	0.3680	$10.00	0.7360	0.7360
C.A.R.E.S. (12)	$5.00	0.4414	0.4414	$10.00	0.7360	0.5860
C.A.R.E.S. Medical Life Support (13)	$5.00	0.4414	0.4414	$10.00	0.7360	0.5860
COMMERCIAL						
Small Volume Commercial (20)	$7.50	0.3838		$13.00	0.5875	
Small Volume Commercial Air Conditioning (21)	$7.50	0.3838	0.3270	$13.00	0.5875	0.5875
Large Volume Commercial (22)	$75.00	0.3400		$95.00	0.5447	
Large Volume Commercial Air Conditioning (23)	$75.00	0.3400	0.3250	$95.00	0.5447	0.5447
INDUSTRIAL						
Small Volume Industrial (30)	$25.00	0.3445		$13.00	0.5630	
Small Volume Industrial Air Conditioning (31)	$25.00	0.3445	0.3300	$13.00	0.5630	0.5630
Large Volume Industrial (32)	$75.00	0.3077		$95.00	0.4831	
Large Volume Industrial Air Conditioning (33)	$75.00	0.3077	0.2922	$95.00	0.4831	0.4831
Public Authority						
Small Volume Public Authority (40)	$7.50	0.3754		$13.00	0.6389	
Small Volume Public Authority Air Conditioning (41)	$7.50	0.3754	0.3231	$13.00	0.6389	0.6389
Large Volume Public Authority (42)	$75.00	0.3223		$95.00	0.5533	
Large Volume Public Authority Air Conditioning (43)	$75.00	0.3223	0.3073	$95.00	0.5533	0.5533
Special Gas Light Service (44)						
Lake Havasu City						
Lighting Group A	$8.41			$13.19		
Lighting Group B	10.09			15.82		
Lighting Group C	11.23			17.61		
Single Orifice	14.70			23.06		
Double Orifice	24.50			38.43		
Triple Orifice	34.00			53.32		
Quadruple Orifice	44.10			69.17		
Irrigation Rate (60)	7.50	0.3801		13.00	0.4821	
Cogenration Rate	$50.00	0.3303	0.3238	$95.00	0.4677	0.4677
T-1 Large Volume Commercial	$75.00	0.0900		$95.00	0.1567	
T-1 Large Volume Industrial	$75.00	0.0577		$95.00	0.1098	
T-1 Large Volume Public Authority	$75.00	0.0723		$95.00	0.1414	
T-2 Large Volume Industrial	n/a	n/a		$1,744.86	0.0000	

CITIZENS COMMUNICATIONS
NORTHERN ARIZONA GAS DIVISION
TWELVE MONTHS ENDED DECEMBER 31, 2001
COMBINED NAGD & SCGD RATE DESIGN

Sample Rate Design
Residential Rate Design Work Paper

	Description	Source	R-10 Residentail	R-11 Resi A/C	R-12 CARES	R-13 CARES -Medical	Booked Residential	Adjusted to Billed
	Billing Units							
1	Customer Bills		1,272,251	60	35,041	24	1,307,376	1,298,979
2	Total Therms		66,270,508	3,863	1,489,179	1,284	67,764,834	67,326,698
3	Booked to Billed Ratio		0.99334	0.99650	1.00223	1.00501		
4								
5	Target Revenues	pg 2, ln 6					$62,400,502	
6	Add Back CARES Discount	pg 2, ln 6					$147,913	
7	Target Before Discount	5+6					$62,548,414	
8								
9	Embedded Gas Costs							
10	Allocated Gas Costs	pg 2, ln 6					30,122,827	
11	less PGA Recovvery	pg 2, ln 6					2,616,920	
12	Gas Costs in Base Rates	10-11					$27,505,908	
13	Therms	2						67,326,698
14	Unit Cost of Embedded Gas in Base Rates	12/13						$ 0.408544
15								
16	Increase in Delivery Rates							
17	Gas Costs Embeded in Base Rates	12					$27,505,908	
18	Remaining Revenues (from Cust & Base Rates)	7-17					$35,042,507	
19	Present Base Revenues (Excluding All Gas Costs	pg 1, ln 13					$19,410,118	
20	Percent Increase in Delivery Rates	18/19-1					80.54%	
21								
22	Customer Charge Development							
23	Present Customer Charge							$ 5.00
24	Cap of Customer Charge over Average Increase	Input						10%
25	Prelim Customer Charge Increase	23*(1+20)*(1+23)						$ 9.93
26	Customer Costs to Serve	Sched G-6						$ 15.93
27	**Proposed Customer Charge**	min(25,26), rounded						**$ 10.00**
28								
29	Non-Gas Revenues							
30	Bills	1						1,298,979
31	Customer Charge Revenue	2*27						$12,989,791
32	Revenue from Volume Charge	18-31						$22,052,715
33	Therms	2						67,326,698
34	Volumetric rate	32/33						$ 0.327548
35								
36	Volumetric Rates							
37	Add Back Embedded Gas Cossts	14						$ 0.408544
38	Total volumetric Charge	34+37						$ 0.736092
39	**Rounded Price (Before CARES Discounts)**	38						**$ 0.736100**

NOTES:
Billing units adjusted by booked to billed ratio. Thus, booked revenue targets divided by adjusted billing units result in billing prices.

CITIZENS COMMUNICATIONS COMPANY
COMBINED ARIZONA GAS DIVISIONS
TWELVE MONTHS ENDED DECEMBER 31, 2001
DEVELOPMENT OF CARES DISCOUNT

Line No.	Combined	Customers	Therms (First 100 Nov - Apr)	Base Rate	Discount Rate	Discount Amount
1	BUDGETED CARES PROGRAM COSTS					$220,000
2						
3	LESS: PROGRAM EXPENSES					$70,000
4						
5	BUDGETED CARES DISCOUNT					$150,000
6	DIVIDED BY APPLICABLE THERMS					986,085
7	CARES DISCOUNT (ROUNDED)					$0.1500
8						
9	COMBINED RATE DESIGN					
10	CARES	2920	985,194	0.736	0.5860	147,779
11	CARES MED LIFE SUPPORT	2	891	0.736	0.5860	134
12	GRAND TOTAL					147,913
13						
14	CARES PROGRAM EXPENSES					$70,000
15	TARGET PROGRAM COST RECOVERY					$217,913
16	TOTAL CONSUMPTION					130,937,155
17	CARES SURCHARGE					$0.001660
18						
19						
20						
21						

Line No.	NAGD	Customers	Therms (First 100 Nov - Apr)	Base Rate	Discount Rate	Discount Amount
22	NAGD					
23						
24	BUDGETED CARES PROGRAM COSTS					$134,704
25						
26	LESS: PROGRAM EXPENSES					$42,860
27						
28	BUDGETED CARES DISCOUNT					$91,844
29	DIVIDED BY APPLICABLE THERMS					603,771
30	CARES DISCOUNT (ROUNDED)					$0.1500
31						
32						
33	NAGD RATE DESIGN					
34	CARES	1550	603,306	0.7348	0.5848	$90,496
35	CARES MED LIFE SUPPORT	1	465	0.7348	0.5848	$70
36	GRAND TOTAL					$90,566
37						
38	CARES PROGRAM EXPENSES					$42,860
39	TARGET PROGRAM COST RECOVERY					$133,426
40	TOTAL CONSUMPTION					125,885,718
41	CARES SURCHARGE					$0.001060
42						
43						
44						
45						

Line No.	SCGD	Customers	Therms (First 100 Nov - Apr)	Base Rate	Discount Rate	Discount Amount
46	SCGD					
47						
48	BUDGETED CARES PROGRAM COSTS					$85,296
49						
50	LESS: PROGRAM EXPENSES					$27,140
51						
52	BUDGETED CARES DISCOUNT					$58,156
53	DIVIDED BY APPLICABLE THERMS					382,314
54	CARES DISCOUNT (ROUNDED)					$0.1500
55						
56	SCGD					
57	CARES	1370	381,888	0.7606	0.6106	$57,283
58	CARES MED LIFE SUPPORT	1	426	0.7606	0.6106	$64
59	TOTAL SCGD CONSUMPTION					$57,347
60						
61	CARES PROGRAM EXPENSES					$27,140
62	TARGET PROGRAM COST RECOVERY					$84,487
63	TOTAL CONSUMPTION					5,051,437
64	CARES SURCHARGE					$0.016730

CITIZENS COMMUNICATIONS COMPANY
COMBINED ARIZONA GAS DIVISIONS
TWELVE MONTHS ENDED DECEMBER 31, 2001
EMBEDDED GAS COSTS

LINE NO.	CLASS/RATE	NAGD	SCGD	COMBINED	WEIGHTED AVERAGE
	(1)	(2)	(3)	(4)	
1	RESIDENTIAL				
2	Residential Service	0.4092	0.3944	0.4085	0.4085
3	Residential Service Air Conditioning	0.4013	0.0000	0.4003	0.4085
4	C.A.R.E.S.	0.4101	0.3963	0.4123	0.4085
5	C.A.R.E.S. Medical Life Support	0.4176	0.3973	0.4171	0.4085
6					
7					
8	COMMERCIAL				
9	Small Volume Commercial	0.3917	0.3965	0.3919	0.3919
10	Small Volume Commercial Air Conditioning	0.3592	0.0000	0.3582	0.3919
11	Large Volume Commercial Excl T1	0.3890	0.0000	0.3880	0.3880
12	Large Volume Commercial Air Conditioning	0.0000	0.0000	0.0000	0.0000
13					
14					
15	INDUSTRIAL				
16	Small Volume Industrial	0.3927	0.4369	0.3972	0.3972
17	Small Volume Industrial Air Conditioning	0.0000	0.0000	0.0000	0.0000
18	Large Volume Industrial Excl T1	0.3743	0.0000	0.3733	0.3733
19	Large Volume Industrial Air Conditioning	0.0000	0.0000	0.0000	0.0000
20					
21					
22	Public Authority				
23	Small Volume Public Authority	0.4147	0.4243	0.4157	0.4157
24	Small Volume Public Authority Air Conditioning	0.0000	0.0000	0.0000	0.0000
25	Large Volume Public Authority Excl T1	0.4130	0.0000	0.4119	0.4119
26	Large Volume Public Authority Air Conditioning	0.0000	0.0000	0.0000	0.0000
27					
28					
29	Special Gas Light Service	0.3526	0.0000	0.3516	0.3516
30					
31	Irrigation	0.4073	0.0000	0.4060	0.4060
32					
33	Cogeneration Rate	0.3594	0.3254	0.3578	0.3578

Citizens Communications Company
Arizona Gas Division

Original Sheet No. 1

NATURAL GAS RATES
SUMMARY OF FILED TARIFFS

CURRENT RATES

Sheet No.	Rate Designation	Rate Description	Effective Date	Customer Charge	Margin	Gas Cost	Basic Cost of Service Rate	Approving Decision No.
1		Summary of Filed Tariffs						
2	R-10	Residential		$ 10.00	$ 0.3275	$ 0.4085	$ 0.7360	
3	R-12	CARES		$ 10.00	$ 0.1775	$ 0.4085	$ 0.5860	
4	R-12	(continuation page)						
5		(Reserved for Future Use)						
6	C-20	Small Volume Commercial		$ 13.00	$ 0.1956	$ 0.3919	$ 0.5875	
7	C-22	Large Vol. Commerical		$ 95.00	$ 0.1714	$ 0.3733	$ 0.5447	
8		(Reserved for Future Use)						
9	I-30	Small Volume Industrial		$ 13.00	$ 0.1658	$ 0.3972	$ 0.5630	
10	I-30	(continuation page)						
11	I-32	Large Vol. Industrial		$ 95.00	$ 0.1098	$ 0.3733	$ 0.4831	
12	I-32	(continuation page)						
13	PA-40	Small Vol. Public Authority		$ 13.00	$ 0.2232	$ 0.4157	$ 0.6389	
14	PA-42	Lg. Vol. Public Authority		$ 95.00	$ 0.1414	$ 0.4119	$ 0.5533	
15		(Reserved for Future Use)						
16	PA-44	Special Gas Light Service			various			
17	PA-44	(continuation page)						
18		(Reserved for Future Use)						
19	IR-60	Irrigation Service		$ 13.00	$ 0.0761	$ 0.4060	$ 0.4821	
20	T-1	Transportation						
21	T-1	(continuation page)						
22	T-1	(continuation page)						
23	T-1	(continuation page)						
24	T-1	(continuation page)			Otherwise applicable base rates less embedded gas costs			
25	T-1	(continuation page)						
26	T-1	(continuation page)						
27	T-1	(continuation page)						
28	T-1	(continuation page)						
29		(Reserved for Future Use)						
30	T-2	Dedicated Transportation						
31	T-2	(continuation page)						
32	T-2	(continuation page)						
33	T-2	(continuation page)						
34	T-2	(continuation page)						
35	T-2	(continuation page)			Cost to service + subsidies (Including $95 Customer Charge)			
36	T-2	(continuation page)						
37	T-2	(continuation page)						
38	T-2	(continuation page)						
39	T-2	(continuation page)						
40	T-2	(continuation page)						
41		(Reserved for Future Use)						
42	CNG-1	Compressed Natural Gas		various			$ -	
43		(Reserved for Future Use)						
44	EC-1	Electric Cogeneration		$95.00	$ 0.1099	$ 0.3578	$ 0.4677	
45	EC-1	(continuation page)						
46	CGS-1	Competitive Gas			negotiated			
47	CGS-1	(continuation page)						
48		(Reserved for Future Use)						
49	NSP-1	Negotiated Sales Program			negotiated			
50		(Reserved for Future Use)						
51	MISC-1	Miscellaneous Tariffs			various			
52		(Reserved for Future Use)						
53	RR-1	Purchased Gas Adj. Clause						
54	RR-1	(continuation page)						
55	RR-1	(continuation page)						
56	RR-1	(continuation page)						

PREVIOUS RATES

Sheet No.	Rate Desig.	Effective Date	Approving Decision No.
1	10	11/1/96	59875
2	11	11/1/96	59875
3	12	11/1/96	59875
4	12	11/1/96	59875
5	13	11/1/96	59875
6	13	11/1/96	59875
7	20	11/1/96	59875
8	21	11/1/96	59875
9	22	11/1/96	59875
10	23	11/1/96	59875
11	23	11/1/96	59875
12	30	11/1/96	59875
13	31	11/1/96	59875
14	32	11/1/96	59875
15	32	11/1/96	59875
16	33	11/1/96	59875
17	33	11/1/96	59875
18	40	11/1/96	59875
19	41	11/1/96	59875
20	42	11/1/96	59875
21	43	11/1/96	59875
22	43	11/1/96	59875
23	44	11/1/96	59875
24	44	11/1/96	59875
25	60	11/1/96	59875
26	CNG-1	11/1/96	59875
27	C-1	11/1/96	59875
28	C-1	11/1/96	59875
29	NSAM	11/1/96	59875
30	CGS	11/1/96	59875
31	CGS	11/1/96	59875
32	Misc Svc	11/1/96	59875
33	T-1	11/1/96	59875
34	T-1	11/1/96	59875
35	T-1	11/1/96	59875
36	T-1	11/1/96	59875
37	T-1	11/1/96	59875
38	T-1	11/1/96	59875
39	T-1	11/1/96	59875
40	T-1	10/1/01	64054
40.1	T-1	10/1/01	64054
41	none	6/1/01	63678
42	RR1	11/1/96	various

NOTES:
1 Only primary rates are shown when multiple blocks are present.

Issued: ____________ Effective: ____________

Issued by: Gary Smith, Vice President and General Manager, Citizens Communications Company,
2901 N. Central Avenue, Suite 1660, Phoenix, Arizona 85012

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Citizens Utilities Company
Northern Arizona Gas Division
Miscellaneous Service Fees
Labor Rates

1	Supervisor		$26.31
2			
3	Customer Service Representative	CSR	$10.94
4			
5	Service Person		$20.14
6			
7	Service Person - After Hours		$30.21
8			
9	Dispatcher		$14.04
10			
11			
12	Transportation Rate		$0.450

Citizens Utilities Company
Northern Arizona Gas Division
Miscellaneous Service Fees
Overhead Loader

1	Payroll Overhead Loader		29.00%
2			
3			
4			
5	Allowance for Non-Productive		
6	Holidays, Vacation Days, etc	27	
7	Total Workdays	261	
8	Overhead Loader		10.34%
9			
10			
11			
12	Total Overhead Loader		39.34%

Citizens Utilities Company
Northern Arizona Gas Division
Miscellaneous Service Fees
Analysis of Service Transfer Fee

1 Description of Charge

The charge for transfer of service from one customer to another, when meter is not turned off.

2 Explanation of Cost

Costs are assoctiated with initiation of service based on Customer Service handling the request, recording the information, transferring and scheduling a service person, activating the service and recording the activation.

3 Estimate of Cost

	Hours	Rate	Cost
CSR	0.25	10.94	2.74
Serviceperson	0.33	20.14	6.65
Dispatcher	0.085	14.04	1.19
Supervisor	0.085	26.31	2.24
Total			12.81

Labor O/H	Percent	39.34%
	Cost	$5.04
Transportation	Miles	10.00
	Rate	0.450
	Cost	$4.50
Other Expenses		$0.00
Tools, Uniform, Materials		
Total Cost		$22.35

4 Present Charge $10.00

5 Proposed Charge $15.00

6 Revenue Summary

	Jan	Feb	Mar	Apr	May	Jun
Monthly Activity	1,048.9	908.5	1,654.0	1,153.5	1,371.5	1,752.0
Present Revenue	$ 10,489.25	$ 9,085.00	$ 16,540.00	$ 11,535.00	$ 13,715.00	$ 17,520.00
Proposed Revenue	$15,733.88	$13,627.50	$24,810.00	$17,302.50	$20,572.50	$26,280.00

	Jul	Aug	Sep	Oct	Nov	Dec	Total
Monthly Activity	1,595.0	1,890.0	1,867.5	1,613.9	1,476.0	1,320.5	17,651.4
Present Revenue	$ 15,950.00	$ 18,900.00	$ 18,675.00	$ 16,139.41	$ 14,760.00	$ 13,205.00	$176,513.66
Proposed Revenue	$23,925.00	$28,350.00	$28,012.50	$24,209.12	$22,140.00	$19,807.50	$264,770.49

Citizens Utilities Company
Northern Arizona Gas Division
Miscellaneous Service Fees
Analysis of Collection Fee

1 Description of Charge

The charge for collecting payments or payment agreements in the field.

2 Explanation of Cost

Costs are associated with identification of the customer for field collection, notification of the customers, assignment and scheduling of the field collector, transportation and collection activities and documentation of event.

3 Estimate of Cost

	Hours	Rate	Cost
CSR	0.33	10.94	3.61
Serviceperson	0.5	20.14	10.07
Dispatcher	0.085	14.04	1.19
Supervisor	0.085	26.31	2.24
Total			17.11

Labor O/H	Percent	39.34%
	Cost	$6.73
Transportation	Miles	10.00
	Rate	0.450
	Cost	$4.50
Other Expenses		$0.00
Total Cost		$28.34

4 Present Charge $10.00

5 Proposed Charge $20.00

6 Revenue Summary

	Jan	Feb	Mar	Apr	May	Jun	
Monthly Activity	1.0	(1.5)	(1.0)	113.0	199.0	119.0	
Present Revenue	$ 10.00	$ (15.00)	$ (10.00)	$ 1,130.00	$ 1,990.00	$ 1,190.00	
Proposed Revenue	$20.00	($30.00)	($20.00)	$2,260.00	$3,980.00	$2,380.00	
	Jul	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Monthly Activity	114.0	50.0	52.0	76.0	58.0	62.0	841.5
Present Revenue	$ 1,140.00	$ 500.00	$ 520.00	$ 760.00	$ 580.00	$ 620.00	$8,415.00
Proposed Revenue	$2,280.00	$1,000.00	$1,040.00	$1,520.00	$1,160.00	$1,240.00	$16,830.00

Citizens Utilities Company
Northern Arizona Gas Division
Miscellaneous Service Fees
Analysis of Establishment of Service - Normal Hours

1 Description of Charge

Fee is charged to establish new service to a customer during normal business hours (8:30 AM to 4:30 PM).

2 Explanation of Cost

Clerical, serviceman's and supervision time plus transportation to connect service, process and verify data, obtain customer information, issue connect orders, and set up new customer record.

3 Estimate of Cost

	Hours	Rate	Cost
CSR	0.25	10.94	2.74
Serviceperson	0.75	20.14	15.11
Dispatcher	0.085	14.04	1.19
Supervisor	0.085	26.31	2.24
Total			21.27

Labor O/H	Percent	39.34%
	Cost	$8.37
Transportation	Miles	10.00
	Rate	0.450
	Cost	$4.50
Other Expenses		$0.00
Total Cost		$34.14

4 Present Charge $15.00

5 Proposed Charge $25.00

6 Revenue Summary

	Jan	Feb	Mar	Apr	May	Jun
Monthly Activity	814.8	769.3	929.9	829.3	881.3	1,234.3
Present Revenue	$ 12,221.28	$ 11,538.84	$ 13,948.91	$ 12,440.00	$ 13,220.00	$ 18,515.00
Proposed Revenue	$20,368.80	$19,231.40	$23,248.18	$20,733.33	$22,033.33	$30,858.33

	Jul	Aug	Sep	Oct	Nov	Dec	Total
Monthly Activity	1,062.0	1,181.1	1,335.1	1,327.4	1,478.0	1,511.3	13,353.8
Present Revenue	$ 15,930.00	$ 17,717.00	$ 20,026.00	$ 19,911.00	$ 22,170.12	$ 22,669.21	$200,307.36
Proposed Revenue	$26,550.00	$29,528.33	$33,376.67	$33,185.00	$36,950.20	$37,782.02	$333,845.60

Citizens Utilities Company
Northern Arizona Gas Division
Miscellaneous Service Fees
Analysis of Establishment of Service - After Hours

1 Description of Charge

Fee is charged to establish new service to a customer after normal business hours, when a serviceman is scheduled before he has left for the day

2 Explanation of Cost

Clerical, serviceman's and supervision time plus transportation to connect service, process and verify data, obtain customer information, issue connect orders, and set up new customer record.

3 Estimate of Cost

	Hours	Rate	Cost
CSR	0.25	10.94	2.74
Serviceperson	0.75	30.21	22.66
Dispatcher	0.085	14.04	1.19
Supervisor	0.085	26.31	2.24
Total			28.82

Labor O/H	Percent	39.34%
	Cost	$11.34
Transportation	Miles	10.00
	Rate	0.450
	Cost	$4.50
Other Expenses		$0.00
Total Cost		$44.66

4 Present Charge $20.00

5 Proposed Charge $35.00

6 Revenue Summary

	Jan	Feb	Mar	Apr	May	Jun
Monthly Activity	2.3	1.3	2.0	3.3	2.0	1.0
Present Revenue	$ 46.00	$ 25.00	$ 40.00	$ 66.00	$ 40.00	$ 20.00
Proposed Revenue	$80.50	$43.75	$70.00	$115.50	$70.00	$35.00

	Jul	Aug	Sep	Oct	Nov	Dec	Total
Monthly Activity	7.1	3.3	1.0	6.6	13.2	13.5	56.6
Present Revenue	$ 142.00	$ 66.00	$ 20.00	$ 132.00	$ 264.00	$ 270.00	$1,131.00
Proposed Revenue	$248.50	$115.50	$35.00	$231.00	$462.00	$472.50	$1,979.25

Citizens Utilities Company
Northern Arizona Gas Division
Miscellaneous Service Fees
Analysis of Establishment of Service - Call out

1 Description of Charge

Fee is charged to establish new service to a customer after normal business hours when the service man is called back to work.

2 Explanation of Cost

Clerical, serviceman's and supervision time plus transportation to connect service, process and verify data, obtain customer information, issue connect orders, and set up new customer record.

3 Estimate of Cost

	Hours	Rate	Cost
CSR	0.25	10.94	2.74
Serviceperson	1	30.21	30.21
Dispatcher	0.085	14.04	1.19
Supervisor	0.085	26.31	2.24
Total			36.37

Labor O/H	Percent	39.34%
	Cost	$14.31
Transportation	Miles	20.00
	Rate	0.450
	Cost	$9.00
Other Expenses		$0.00
Total Cost		$59.69

4 Present Charge $46.00

5 Proposed Charge $50.00

6 Revenue Summary

	Jan	Feb	Mar	Apr	May	Jun
Monthly Activity	15.0	9.0	9.0	19.0	11.0	3.0
Present Revenue	$ 690.00	$ 414.00	$ 414.00	$ 874.00	$ 506.00	$ 138.00
Proposed Revenue	$750.00	$450.00	$450.00	$950.00	$550.00	$150.00

	Jul	Aug	Sep	Oct	Nov	Dec	Total
Monthly Activity	6.0	3.0	7.0	5.0	4.0	10.0	101.0
Present Revenue	$ 276.00	$ 138.00	$ 322.00	$ 230.00	$ 184.00	$ 460.00	$4,646.00
Proposed Revenue	$300.00	$150.00	$350.00	$250.00	$200.00	$500.00	$5,050.00

Citizens Utilities Company
Northern Arizona Gas Division
Miscellaneous Service Fees
Analysis of Service Reconnect - Norm Hours

1 Description of Charge

The Reconnect/Dispatch Order to Disconnect fee is charged to cover the cost of preparing and dispatching an order to disconnect by customer request including the reconnection of service.

2 Explanation of Cost

Clerical, serviceman and supervision time plus transportation to process order including disconnecting and reconnecting service.

3 Estimate of Cost

	Hours	Rate	Cost
CSR	0.5	10.94	5.47
Serviceperson	1.166	20.14	23.48
Dispatcher	0.166	14.04	2.33
Supervisor	0.166	26.31	4.37
Total			35.65

Labor O/H	Percent	39.34%
	Cost	$14.03
Transportation	Miles	10.00
	Rate	0.450
	Cost	$4.50
Other Expenses		$0.00
Total Cost		$54.18

4 Present Charge $25.00

5 Proposed Charge $35.00

6 Revenue Summary

	Jan	Feb	Mar	Apr	May	Jun
Monthly Activity	1.1	0.8	0.7	26.9	35.7	30.9
Present Revenue	$26.50	$20.00	$17.50	$673.00	$892.66	$772.50
Proposed Revenue	$37.10	$28.00	$24.50	$942.20	$1,249.73	$1,081.50

	Jul	Aug	Sep	Oct	Nov	Dec	Total
Monthly Activity	24.8	23.8	16.4	26.1	27.7	23.2	238.1
Present Revenue	$619.00	$594.20	$410.80	$653.00	$692.70	$581.20	$5,953.07
Proposed Revenue	$866.60	$831.88	$575.12	$914.20	$969.78	$813.68	$8,334.29

Citizens Utilities Company
Northern Arizona Gas Division
Miscellaneous Service Fees
Analysis of Service Reconnect - After Hours

1 Description of Charge

The Reconnect/Dispatch Order to Disconnect fee is charged to cover the cost of preparing and dispatching an order to disconnect by customer request, including the reconnection of service.

2 Explanation of Cost

Clerical, serviceman and supervision time plus transportation to process order including disconnecting and reconnecting service.

3 Estimate of Cost

	Hours	Rate	Cost
CSR	0.5	10.94	5.47
Serviceperson	1.166	26.61	31.03
Dispatcher	0.166	14.04	2.33
Supervisor	0.166	26.31	4.37
Total			43.20

Labor O/H	Percent	39.34%
	Cost	$17.00
Transportation	Miles	10.00
	Rate	0.450
	Cost	$4.50
Other Expenses		$0.00
Total Cost		$64.70

4 Present Charge $35.00

5 Proposed Charge $45.00

6 Revenue Summary

	Jan	Feb	Mar	Apr	May	Jun
Monthly Activity	0.0	0.1	0.1	0.5	0.4	0.3
Present Revenue	$0.00	$4.60	$4.60	$17.50	$14.00	$10.00
Proposed Revenue	$0.00	$5.91	$5.91	$22.50	$18.00	$12.86

	Jul	Aug	Sep	Oct	Nov	Dec	Total
Monthly Activity	0.7	0.4	0.0	0.2	0.2	0.7	3.6
Present Revenue	$24.50	$14.00	$0.00	$7.00	$7.00	$24.50	$127.70
Proposed Revenue	$31.50	$18.00	$0.00	$9.00	$9.00	$31.50	$164.19

Citizens Utilities Company
Northern Arizona Gas Division
Miscellaneous Service Fees
Analysis of Service Reconnnect - Call Out

1 Description of Charge

The Reconnect/Dispatch Order to Disconnect fee is charged to cover the cost of preparing and dispatching an order to disconnect by customer request including the reconnection of service.

2 Explanation of Cost

Clerical, serviceman and supervision time plus transportation to process order including disconnecting and reconnecting service.

3 Estimate of Cost

	Hours	Rate	Cost
CSR	0.5	10.94	5.47
Serviceperson	1.417	27.25	38.61
Dispatcher	0.166	14.04	2.33
Supervisor	0.166	26.31	4.37
Total			50.78

Labor O/H	Percent	39.34%
	Cost	$19.98
Transportation	Miles	20.00
	Rate	0.450
	Cost	$9.00
Other Expenses		$0.00
Total Cost		$79.76

4 Present Charge $46.00

5 Proposed Charge $60.00

6 Revenue Summary

	Jan	Feb	Mar	Apr	May	Jun
Monthly Activity	0.2	0.2	0.3	1.7	2.9	1.8
Present Revenue	$9.20	$9.20	$13.80	$78.20	$135.31	$82.80
Proposed Revenue	$12.00	$12.00	$18.00	$102.00	$176.49	$108.00

	Jul	Aug	Sep	Oct	Nov	Dec	Total
Monthly Activity	0.9	1.6	1.6	0.8	0.5	1.0	13.6
Present Revenue	$43.32	$73.60	$73.60	$36.80	$23.00	$48.20	$627.03
Proposed Revenue	$56.51	$96.00	$96.00	$48.00	$30.00	$62.87	$817.86

Citizens Utilities Company
Northern Arizona Gas Division
Miscellaneous Service Fees
Analysis of Nonpay Service Reconnect - Normal Hours

1 Description of Charge

The Reconnect/Dispatch Order to Disconnect fee is charged to cover the cost of preparing and dispatching an order to disconnect for nonpayment, including the reconnection of service.

2 Explanation of Cost

Clerical, serviceman and supervision time plus transportation to process order including disconnecting and reconnecting service.

3 Estimate of Cost

	Hours	Rate	Cost
CSR	0.75	10.94	8.21
Serviceperson	1.166	20.14	23.48
Dispatcher	0.166	14.04	2.33
Supervisor	0.166	26.31	4.37
Total			38.39

Labor O/H	Percent	39.34%
	Cost	$15.10
Transportation	Miles	10.00
	Rate	0.450
	Cost	$4.50
Other Expenses		$0.00
Total Cost		$57.99

4 Present Charge $25.00

5 Proposed Charge $45.00

6 Revenue Summary

	Jan	Feb	Mar	Apr	May	Jun
Monthly Activity	9.5	7.2	6.3	242.3	321.4	278.1
Present Revenue	$238.50	$180.00	$157.50	$6,057.00	$8,033.97	$6,952.50
Proposed Revenue	$429.30	$324.00	$283.50	$10,902.60	$14,461.14	$12,514.50

	Jul	Aug	Sep	Oct	Nov	Dec	Total
Monthly Activity	222.8	213.9	147.9	235.1	249.4	209.2	2,143.1
Present Revenue	$5,571.00	$5,347.80	$3,697.22	$5,877.00	$6,234.30	$5,230.80	$53,577.59
Proposed Revenue	$10,027.80	$9,626.04	$6,654.99	$10,578.60	$11,221.74	$9,415.44	$96,439.65

Citizens Utilities Company
Northern Arizona Gas Division
Miscellaneous Service Fees
Analysis of Nonpay Service Reconnect - After Hours

1 Description of Charge

Fee is charged to establish new service to a customer after normal business hours.

2 Explanation of Cost

he Reconnect/Dispatch Order to Disconnect fee is charged to cover the cost of preparing and dispatching an order to disconnect for nonpayment, including the reconnection of service.

3 Estimate of Cost

	Hours	Rate	Cost
CSR	0.75	10.94	8.21
Serviceperson	1.166	26.61	31.03
Dispatcher	0.166	14.04	2.33
Supervisor	0.166	26.31	4.37
Total			45.93

Labor O/H	Percent	39.34%
	Cost	$18.07
Transportation	Miles	10.00
	Rate	0.450
	Cost	$4.50
Other Expenses		$0.00
Total Cost		$68.51

4 Present Charge $35.00

5 Proposed Charge $55.00

6 Revenue Summary

	Jan	Feb	Mar	Apr	May	Jun	
Monthly Activity	0.0	1.2	1.2	4.5	3.6	2.6	
Present Revenue	$0.00	$41.40	$41.40	$157.50	$126.00	$90.00	
Proposed Revenue	$0.00	$65.06	$65.06	$247.50	$198.00	$141.43	
	Jul	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Monthly Activity	6.3	3.6	0.0	1.8	1.8	6.3	32.8
Present Revenue	$220.50	$126.00	$0.00	$63.00	$63.00	$220.50	$1,149.30
Proposed Revenue	$346.50	$198.00	$0.00	$99.00	$99.00	$346.50	$1,806.04

Citizens Utilities Company
Northern Arizona Gas Division
Miscellaneous Service Fees
Analysis of Nonpay Service Reconnect - Call Out

1 Description of Charge

The Reconnect/Dispatch Order to Disconnect fee is charged to cover the cost of preparing and dispatching an order to disconnect for nonpayment, including the reconnection of service.

2 Explanation of Cost

Clerical, serviceman and supervision time plus transportation to process order including disconnecting and reconnecting service.

3 Estimate of Cost

	Hours	Rate	Cost
CSR	0.75	10.94	8.21
Serviceperson	1.417	27.25	38.61
Dispatcher	0.166	14.04	2.33
Supervisor	0.166	26.31	4.37
Total			53.51

Labor O/H	Percent	39.34%
	Cost	$21.05
Transportation	Miles	20.00
	Rate	0.450
	Cost	$9.00
Other Expenses		$0.00
Total Cost		$83.57

4 Present Charge $46.00

5 Proposed Charge $65.00

6 Revenue Summary

	Jan	Feb	Mar	Apr	May	Jun
Monthly Activity	1.8	1.8	2.7	15.3	26.5	16.2
Present Revenue	$82.80	$82.80	$124.20	$703.80	$1,217.75	$745.20
Proposed Revenue	$117.00	$117.00	$175.50	$994.50	$1,720.74	$1,053.00

	Jul	Aug	Sep	Oct	Nov	Dec	Total
Monthly Activity	8.5	14.4	14.4	7.2	4.5	9.4	122.7
Present Revenue	$389.90	$662.40	$662.40	$331.20	$207.00	$433.80	$5,643.25
Proposed Revenue	$550.94	$936.00	$936.00	$468.00	$292.50	$612.98	$7,974.16

Citizens Utilities Company
Northern Arizona Gas Division
Miscellaneous Service Fees
Analysis of Customer Requested Meter Re-Read

1 Description of Charge

Fee charged when a customer requests a re-read of the meter and the original reading is correct when there is no evidence from usage history of a meter misread in the current or previous month

2 Explanation of Cost

Clerical, Serviceman and Supervision time plus transportation to issue order and complete service call.

3 Estimate of Cost

	Hours	Rate	Cost
CSR	0.1667	10.94	1.82
Serviceperson	0.33	20.14	6.65
Dispatcher	0.0833	14.04	1.17
Supervisor	0.0833	26.31	2.19
Total			11.83

Labor O/H	Percent	39.34%
	Cost	$4.65
Transportation	Miles	10.00
	Rate	0.450
	Cost	$4.50
Other Expenses		$0.00
Computer resources		
Total Cost		$20.99

4 Present Charge $5.00

5 Proposed Charge $15.00

6 Revenue Summary

	Jan	Feb	Mar	Apr	May	Jun
Monthly Activity	21.0	6.0	12.0	16.0	5.0	1.0
Present Revenue	$ 105.00	$ 30.00	$ 60.00	$ 80.00	$ 25.00	$ 5.00
Proposed Revenue	$315.00	$90.00	$180.00	$240.00	$75.00	$15.00

	Jul	Aug	Sep	Oct	Nov	Dec	Total
Monthly Activity	2.0	0.0	0.0	0.0	2.0	5.0	70.0
Present Revenue	$ 10.00	$ -	$ -	$ -	$ 10.00	$ 25.00	$350.00
Proposed Revenue	$30.00	$0.00	$0.00	$0.00	$30.00	$75.00	$1,050.00

Citizens Utilities Company
Northern Arizona Gas Division
Miscellaneous Service Fees
Analysis of Customer Requested Meter Test

1 Description of Charge
Fee charged when a customer requests a meter test.

2 Explanation of Cost
Clerical, Serviceman and Supervision time plus transportation to issue order and complete service call.

3 Estimate of Cost

	Hours	Rate	Cost
CSR	0.33	10.94	3.61
Serviceperson	0.917	20.14	18.47
Dispatcher	0.0833	14.04	1.17
Supervisor	0.0833	26.31	2.19
Total			25.44

Labor O/H	Percent	39.34%
	Cost	$10.01
Transportation	Miles	10.00
	Rate	0.450
	Cost	$4.50
Other Expenses Mail and test costs		$49.00
Total Cost		$88.95

4 Present Charge $35.00

5 Proposed Charge $65.00

6 Revenue Summary

	Jan	Feb	Mar	Apr	May	Jun	
Monthly Activity	0.0	0.0	1.0	0.0	0.9	0.0	
Present Revenue	$ -	$ -	$ 35.00	$ -	$ 30.00	$ -	
Proposed Revenue	$0.00	$0.00	$65.00	$0.00	$55.71	$0.00	
	Jul	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
Monthly Activity	0.0	0.0	0.0	0.0	0.0	0.0	1.9
Present Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$65.00
Proposed Revenue	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$120.71

Citizens Utilities Company
Northern Arizona Gas Division
Miscellaneous Service Fees
Analysis of NSF Check

1 Description of Charge

Returned Check Fee is charged when customer's payment is returned unpaid for any reason.

2 Explanation of Cost

Clerical, Supervision, Office and miscellaneous expenses to process customer's returned check.

3 Estimate of Cost

	Hours	Rate	Cost
CSR	0.4167	10.94	4.56
Serviceperson	0	20.14	0.00
Dispatcher	0	14.04	0.00
Supervisor	0.0833	26.31	2.19
Total			6.75

Labor O/H	Percent	39.34%
	Cost	$2.66
Transportation	Miles	0.00
	Rate	0.450
	Cost	$0.00
Other Expenses		$0.00
Mail and test costs		
Total Cost		$9.41

4 Present Charge $15.00

5 Proposed Charge $15.00

6 Revenue Summary

	Jan	Feb	Mar	Apr	May	Jun
Monthly Activity	133.0	102.0	63.0	133.0	140.0	85.0
Present Revenue	$ 1,995.00	$ 1,530.00	$ 945.00	$ 1,995.00	$ 2,100.00	$ 1,275.00
Proposed Revenue	$1,995.00	$1,530.00	$945.00	$1,995.00	$2,100.00	$1,275.00

	Jul	Aug	Sep	Oct	Nov	Dec	Total
Monthly Activity	102.0	79.0	54.0	72.0	79.0	101.0	1,143.0
Present Revenue	$ 1,530.00	$ 1,185.00	$ 810.00	$ 1,080.00	$ 1,185.00	$ 1,515.00	$17,145.00
Proposed Revenue	$1,530.00	$1,185.00	$810.00	$1,080.00	$1,185.00	$1,515.00	$17,145.00

Citizens Utilities Company
Northern Arizona Gas Division
Miscellaneous Service Fees
Analysis of Multiple Attempts to Reconnect

1 Description of Charge

Multiple attempts to establish service due to customer not home or facilities not ready, with 2 failed attempts

2 Explanation of Cost

Clerical, Supervision, Office and miscellaneous expenses

3 Estimate of Cost

	Hours	Rate	Cost
CSR	0.1667	10.94	1.82
Serviceperson	0.33	20.14	6.65
Dispatcher	0.0833	14.04	1.17
Supervisor	0.0833	26.31	2.19
Total			11.83

Labor O/H	Percent	39.34%
	Cost	$4.65
Transportation	Miles	10.00
	Rate	0.450
	Cost	$4.50
Other Expenses		$0.00
Total Cost		$20.99

4 Present Charge $0.00

5 Proposed Charge $15.00

6 Revenue Summary

Monthly Activity	50.0
Present Revenue	$0.00
Proposed Revenue	$750.00

8

Citizens Utilities Company
Arizona Gas Division (Combined)
Summary of Proposed Miscellaneous Service Fees

Line No.	Description	NAGD Current Charge	Proposed Charge	AGD Present Revenue	AGD Proposed Revenue	Change in Revenue	Percent Change	Billing Units
1	Service Transfer Fee	$10.00	$15.00	$176,514	$281,632	$105,118	59.55%	18,775
2	Collection Fee	$10.00	$20.00	$8,415	$17,902	$9,487	112.74%	895
3	Establishment of Service			$0	$0	$0	0.00%	-
4	Normal Business Hours	$15.00	$25.00	$200,307	$355,106	$154,798	77.28%	14,204
5	After Business Hours	$20.00	$35.00	$1,150	$2,014	$865	75.21%	58
6	Call out	$46.00	$50.00	$4,646	$5,372	$726	15.62%	107
7	Re-establishment, Reconnection of Service			$0	$0	$0	0.00%	-
8	Normal Business Hours	$25.00	$35.00	$5,953	$8,865	$2,912	48.92%	253
9	After Business Hours	$35.00	$45.00	$128	$175	$47	36.76%	4
10	Call out	$46.00	$60.00	$627	$870	$243	38.74%	14
11	Re-establishment, Reconnection of Service-Non Pay Disconnect			$0	$0	$0	0.00%	-
12	Normal Business Hours	$25.00	$45.00	$57,043	$102,677	$45,634	80.00%	2,282
13	After Business Hours	$35.00	$55.00	$1,149	$1,921	$772	67.15%	35
14	Call out	$46.00	$65.00	$5,643	$8,482	$2,839	50.30%	130
15	Customer Requested Meter Re-Reads	$5.00	$15.00	$350	$1,117	$767	219.10%	74
16	Customer Requested Meter Test	$35.00	$65.00	$65	$128	$63	97.54%	2
17	Insufficient Funds (NSF) Check	$15.00	$15.00	$17,835	$18,180	$345	1.93%	1,212
18	Multiple Attempts to Connect	$0.00	$15.00	$0	$798	$798	0.00%	53
19								
20								
21	SubTotal			$479,825	$805,237	$325,413	67.82%	
22								
23	Other Fees							
24	Accident Labor Charge			$ 1,935	$ 1,935	$ -	0.00%	
25	Accident Material Charge			$ 569	$ 569	$ -	0.00%	
26	Labor Service Charge			$ 5,864	$ 5,864	$ -	0.00%	
27	Locate Gas Line			$ 180	$ 180	$ -	0.00%	
28	Lost Gas Revenue			$ 392	$ 392	$ -	0.00%	
29	Late Payment Fees			$ 340,573	$ 453,846	$113,272	33.26%	
30	Other Fees			$ 13,647	$ 13,647	$ -	0.00%	
31	Total Miscellaneous Service Fee Revenues			$829,338	$1,268,023	$438,685	52.90%	

Citizens Utilities Company
Northern Arizona Gas Division
Summary of Proposed Miscellaneous Service Fees

Line No.	Description	Current Charge	Proposed Charge	Present Revenue	Proposed Revenue	Change in Revenue	Percent Change	Billing Units
1	Service Transfer Fee	$10.00	$15.00	$176,514	$264,770	$88,257	50.00%	17,651
2	Collection Fee	$10.00	$20.00	$8,415	$16,830	$8,415	100.00%	842
3	Establishment of Service							
4	Normal Business Hours	$15.00	$25.00	$200,307	$333,846	$133,538	66.67%	13,354
5	After Business Hours	$20.00	$35.00	$1,131	$1,979	$848	75.00%	57
6	Call out	$46.00	$50.00	$4,646	$5,050	$404	8.70%	101
7	Re-establishment, Reconnection of Service							
8	Normal Business Hours	$25.00	$35.00	$5,953	$8,334	$2,381	40.00%	238
9	After Business Hours	$35.00	$45.00	$128	$164	$36	28.57%	4
10	Call out	$46.00	$60.00	$627	$818	$191	30.43%	14
11	Re-establishment, Reconnection of Service-Non Pay Disconnect							
12	Normal Business Hours	$25.00	$45.00	$53,578	$96,440	$42,862	80.00%	2,143
13	After Business Hours	$35.00	$55.00	$1,149	$1,806	$657	57.14%	33
14	Call out	$46.00	$65.00	$5,643	$7,974	$2,331	41.30%	123
15	Customer Requested Meter Re-Reads	$5.00	$15.00	$350	$1,050	$700	200.00%	70
16	Customer Requested Meter Test	$35.00	$65.00	$65	$121	$56	85.71%	2
17	Insufficient Funds (NSF) Check	$15.00	$15.00	$17,145	$17,145	$0	0.00%	1,143
18	Multiple Attempts to Connect	$0.00	$15.00	$0	$750	$750	0.00%	50
19								
20								
21	SubTotal			$475,651	$757,077	$281,426	59.17%	
22								
23	Other Fee's							
24	Accident Labor Charge			$ 1,935	$ 1,935	$0	0.00%	
25	Accident Material Charge			$ 569	$ 569	$0	0.00%	
26	Labor Service Charge			$ 5,864	$ 5,864	$0	0.00%	
27	Locate Gas Line			$ 180	$ 180	$0	0.00%	
28	Lost Gas Revenue			$ 392	$ 392	$0	0.00%	
29	Late Payment Fees			$ 324,971	$ 418,337	$ 93,366	28.73%	
30	Other Fees			$ 13,647	$ 13,647	$0	0.00%	
31	Total Miscellaneous Service Fee Revenues			$ 823,209	$ 1,198,001	$374,792	45.53%	

Citizens Utilities Company
Santa Cruz Gas Division
Summary of Proposed Miscellaneous Service Fees

Line No.	Description	Current Charge	Proposed Charge	Present Revenue	Proposed Revenue	Change in Revenue	Percent Change	Billing Units
1	Service Transfer Fee	$0.00	$15.00	$0	$16,861	$16,861	0.00%	1,124
2	Collection Fee	$0.00	$20.00	$0	$1,072	$1,072	0.00%	54
3	Establishment of Service							
4	Normal Business Hours	$0.00	$25.00	$0	$21,260	$21,260	0.00%	850
5	After Business Hours	$18.59	$35.00	$19	$35	$16	88.27%	1
6	Call out	$0.00	$50.00	$0	$322	$322	0.00%	6
7	Re-establishment, Reconnection of Service							
8	Normal Business Hours	$3.00	$35.00	$0	$531	$531	0.00%	15
9	After Business Hours	$0.00	$45.00	$0	$10	$10	0.00%	0
10	Call out	$0.00	$60.00	$0	$52	$52	0.00%	1
11	Re-establishment, Reconnection of Service-Non Pay Disconnect							
12	Normal Business Hours	$25.00	$45.00	$3,465	$6,237	$2,772	80.00%	139
13	After Business Hours	$0.00	$55.00	$0	$115	$115	0.00%	2
14	Call out	$0.00	$65.00	$0	$508	$508	0.00%	8
15	Customer Requested Meter Re-Reads	$0.00	$15.00	$0	$67	$67	0.00%	4
16	Customer Requested Meter Test	$5.00	$65.00	$0	$8	$8	0.00%	0
17	Insufficient Funds (NSF) Check	$10.00	$15.00	$690	$1,035	$345	50.00%	69
18	Multiple Attempts to Connect	$0.00	$15.00	$0	$48	$48	0.00%	3
19								
20								
21	SubTotal			$4,174	$48,160	$43,986	1053.92%	
22								
23	Other Fees							
24	Accident Labor Charge			$ -	$ -	$ -	0.00%	
25	Accident Material Charge			$ -	$ -	$ -	0.00%	
26	Labor Service Charge			$ -	$ -	$ -	0.00%	
27	Locate Gas Line			$ -	$ -	$ -	0.00%	
28	Lost Gas Revenue			$ -	$ -	$ -	0.00%	
29	Late Payment Fees			$ 15,602	$ 35,509	$19,906	127.59%	
30								
31	Total Miscellaneous Service Fee Revenues			$19,776	$83,669	$63,893	323.09%	

Citizens Utilities Company
Arizona Gas Division
Miscellaneous Service Fee Comparison

Line No.	Company	Service Transfer Fee	Collection Fee	Est. of Service Fee _1/	Re-Est. of Service Fee _1/	Cust. Req. Meter Read	Cust. Req. Meter Test	Insuff. Check Funds
1	**Citizens (Proposed Fees)**	**$15.00**	**$20.00**	**$25/$35/$50**	**$35/$45/$60**	**$15.00**	**$65.00**	**$15.00**
2								
3	Ajo Improvement			$25.00	_2/	$10.00	_3/	$10.00
4								
5	Black Mountain Gas			$20.00	_4/	$25.00	$25.00	$15.00
6								
7	Duncan Rural Service			$25.00	$35/$45	$20.00	$50.00	$15.00
8								
9	Broken Bow (Propane)			$10.00	$10.00	_5/	$5.00	
10								
11	Graham County Utilities			$20.00	$30/$45	$10.00	$10.00	$20.00
12								
13	Southwest Gas (Arizona)		$20.00	$30/$40		$10.00	$25.00	$10.00
14								
15	Sierra Pacific	$15.00		$15/$22.50				$5.00
16								
17	Public Service Co. New Mexico		$8.00	$40/$60		$24.00	$30/$50 _6/	$15.00
18								
19	Southern California Gas			$25.00	$16.00		$1/$2/$4 _7/	
20								
21	Baltimore Gas & Electric	Res $20/Com $30	$15.00	Res $40/Com $55	$20/$30/$70			$15.00
22								
23	Western Kentucky Gas			$48/$60 _8/	$34/$40	$12.00	$20.00	$23.00
24								
25	Columbia Gas of Virginia		$16.00	$31.00	$48.00		$100.00	$14.00
26								
27	Washington Gas of Maryland			$40.00	$50/$70			$15.00
28								
29	Citizens (Electric Division)			$20.00	$20/$60	$15.00	$60.00	$10.00
30								
31	Salt River Project			$28/$48		$25.00		$20.00
32								
33	Arizona Public Service Company	$25.00		Res $25/Com $35	$25/$50	$25.00	$2.00	$9.00
34								
35	Southern California Edison	$10.00		$10/$17.50	$20/$25			
36								
37	Tuscon Electric			$13.50	$13.50			
38								
39	Average _9/	$17.50	$14.75	$25.86	$26.79	$17.60	$29.82	$14.00

Citizens Utilities Company
Arizona Gas Division
Miscellaneous Service Fee Comparison

Notes:

_1/ Norm Hrs / After Hrs / Callout

_2/ The monthly minimum, minus the commodity charge (if any) times the number of full months disconnected.

_3/ Cost to include parts, charges, labor and overheads.

_4/ 1) Number of months off-system times monthly minimum charge; 2)Two (2) times the average month bill; 3) Two and one-half (2 1/2) times the average monthly bill.

_5/ If a meter is found within 3% slow or fast, based on the average of check and open flow test method, no billing adjustment shall be made and the customer shall be charged for this special service at the Company's Hourly Rates Then In Effect with a one hour minimum charge. In the event the meter is found to test more than 3% slow or fast, on the basis as stated above, no charge will be made for the testing and customer will receive a billing adjustment based on the corrected consumption determined under the procedures set forth in Section 5, Article (i).

_6/ 300 Cubic foot per hour meter / Greater than 300 cubic foot per hour meter.

_7/ 250 Cubic foot per hour meter / Greater than 250 but not exceeding 400 cubic foot per hour meter / Greater than 400 but not exceeding 4000 cubic foot per hour meter.

_8/ Includes Meter Set Fee and Turn On Fee.

_9/ Excluding Citizens Proposal for Residential during normal business hours where applicable.

9

EXHIBIT
JA-15
admitted

INTRODUCTION

Q. Please state your name.

A. My name is Raymond J. Mason.

Q. By whom and in what capacity are you employed?

A. I am employed by Citizens Communications Company ("Citizens") and its subsidiaries as Director, Corporate Regulatory Affairs. This includes both the Northern Arizona Gas Division ("NAGD") and the Santa Cruz Gas Division ("SCGD") that are identified as the Arizona Gas Division ("AGD" or the "Company") for this combined rate case application.

Q. Please state your business address.

A. My business address is 3 High Ridge Park, Stamford, Connecticut 06905.

Q. What are your duties and responsibilities in your current position?

A. As Director of Corporate Regulatory Affairs, I am involved in a wide range of issues that affect numerous items that arise in Citizens' regulatory proceedings. Among other duties, I am responsible for the preparation, review, and presentation of the allocation of corporate costs to the operating units of Citizens, including the NAGD and SCGD. I am responsible for the development of Citizens' positions regarding the allocation of common costs and recovery of those costs in regulatory proceedings. In addition, I oversee the preparation of depreciation studies and have testified concerning capital recovery before state and federal regulatory commissions.

Q. Please describe your education, training and other experience

A. I graduated from the University of Connecticut with a Bachelor of Science degree in Accounting and a Bachelor of Arts Degree in Economics. I also have an Associates Degree in Computer Programming. Since joining Citizens, I have attended numerous seminars in the fields of capital recovery and public utility ratemaking. I have attended and appeared as a panelist in conferences concerning state and federal regulatory issues. In addition, I have prepared, directed and reviewed depreciation studies for many of Citizens' operating divisions and subsidiaries.

I have presented testimony on behalf of Citizens in the states of Arizona, California, Hawaii, Ohio, Illinois, Louisiana, New York, Nevada, Pennsylvania, West Virginia, and Vermont. My testimony addressed areas of the rate base and the income statement, including employee benefits, executive compensation, property insurance, property liability and personal damages, incentive compensation, and depreciation.

Q. Please describe your employment history with Citizens.

A. I joined Citizens in May of 1988, as Senior Financial Tax Accountant, with responsibility for financial tax accounting as it relates to tax depreciation, deferred income taxes, reconciliation between financial and tax accounting, and related consolidation entries. In September of 1989, I was promoted to Supervisor of Capital Recovery and Plant Analysis, where I focused on book depreciation, Industrial Development Revenue Bond ("IDRB") financing, and Allowance for Funds Used During Construction ("AFUDC") accounting. I was promoted to Manager of Corporate Regulatory Affairs in June of 1993 and to my current position in July of 1994.

Q. What is the purpose of your testimony in this proceeding?

A. I will present direct testimony on:

- General Description of the Contents of the Application
- Testimony Responsibilities
- Summary of Financial Statements ("A" Schedules)
- Net Common Plant Allocation
- Reconstruction Cost New ("RCN") Rate Base Calculation Methodology
- AFUDC Calculation Compliance
- Computation of Working Capital (Schedule B-5)
- CARES Program (Schedule B-11)
- Salaries and Wages (Schedule C-2, Adjustment B)
- Regulatory, Miscellaneous and Per Diem (Schedule C-2, Adjustment D)
- Insurance Expense (Schedule C-2, Adjustment E)
- Injuries and Damages Expenses (Schedule C-2, Adjustment F)
- Welfare and Pension Benefits Expenses (Schedule C-2, Adjustment G)
- Stamford Administrative Office ("SAO") Expense (Schedule C-2. Adjustment L)
- Public Service Organization ("PSO") Expenses (Schedule C-2, Adjustment L)
- LAN – WAN – Email Services ("LWES") Expense (Schedule C-2. Adjustment L)
- CARES Discount and Expense (Schedule C-2, Adjustment Q)
- Cost of Debt and Preferred Stock ("D" Schedules)
- Projections and Forecasts ("F" Schedules)

OVERVIEW OF APPLICATION

Q. Please describe the contents of the filing.

A. The application is made in accordance with the requirements of Arizona Administrative Code Section R14-2-103. Data for the NAGD and SCGD is filed on a combined AGD basis. This filing is organized into nine sections:

- Section A contains summary financial statements.
- Section B includes the required rate base schedules.
- Section C includes test period operating revenues and expenses schedules with related adjustments.
- Section D contains schedules presenting capital structure and the costs of capital.
- Section E includes schedules containing historical financial information.
- Section F reflects forecasted financial information.
- Section G contains the customer class cost of service study.
- Section H includes test year revenue and sales data and the proposed tariffs reflected the rate increases being sought.
- Section I of the application includes the working papers prepared in support of the filing.

These schedules were filed as part of this rate application and are found in their own bound volume.

Q What test year is reflected in the Company's filing?

A. The application reflects a historical test year ended December 31, 2001, normalized and adjusted for certain known and measurable changes in prices and rates that have occurred through June 30, 2002, and an end-of-period rate base, presented on both a net original cost and depreciated reproduction cost basis.

Q. What is the amount of the requested annual increase in gross revenues?

A. The requested increase in annual revenues is $21,005,521, or 28.93 percent.

Q. When were the most recent rate cases for the NAGD and the SCGD?

A. On October 29, 1996, the Arizona Corporation Commission ("Commission") issued Decision No. 59875, approving a settlement agreement between the NAGD and the parties to the case. The Decision approved a $2.7 million annual increase in revenues. The twelve-month test year ended on June 30, 1995.

The last rate order for the SCGD was Commission Decision No. 55585, issued on June 3, 1987, providing for an $86,824 reduction in annual operating revenues. The test year used in that proceeding was the twelve months ended June 30, 1985.

TESTIMONY RESPONSIBILITIES

Q. Please identify the other witnesses filing direct testimony in support of the Company's application and their respective issue areas.

A. The other witnesses filing direct testimony are:

- Mr. Kenneth Cohen, President and Chief Operating Officer of the Public Service Sector ("PSS") (and the Vice President and Controller of the PSS during the test year) will testify on the need for rate relief, the consolidated filing of the Arizona gas properties, the accounting systems and procedures used by the PSS, corporate policy, and the status of Citizens' plans for divesting its public services properties.

- Mr. Gary Smith, the Vice President and General Manager of the Arizona Gas Division, will testify on the Arizona Gas operations and service territories, the need for rate relief, the recently completed NAGD Build-Out Program, budgeted capital expenditures and operating results underlying the projected financial data reflected in the filing, the consolidation of the two Arizona gas operations for ratemaking and operational purposes, the sale of the Yale Street office building, programs benefiting low income customers, and the transfer of a gas line from the Santa Cruz Electric Division to the SCGD; and the increased requirements and safety standards at both federal and state level.
- Mr. Kevin Doherty, Regulatory Manager for Citizens Communications Company, will testify on all of the rate base components (except working capital and accumulated deferred income taxes) including plant-related items, contributions and advances in aid of construction, gains on sale of utility property, customer deposits, and yet-to-be disbursed amounts collected under the Company's Warm Spirit Program. Mr. Doherty's testimony also addresses the income statement and summary of pro forma adjustments, certain revenue adjustments, certain expense adjustments relating to uncollectible expenses, depreciation, lease expenses, gains on sale, Y2K expenses, and postage expenses. He will present the Gross Revenue Conversion Factor. In addition, Mr. Doherty is sponsoring the Section E schedules containing recorded historical financial and statistical data for the test year and two preceding calendar years.

- Mr. Anthony Apuzzo, Director of Tax and Actuarial Compliance for Citizens Communications Company, will testify on the balance of Accumulated Deferred Income Taxes deducted from rate base. He will also testify to certain operating expense items relating to taxes other than income taxes, an adjustment pertaining to prior period tax refunds, and Federal and State income taxes.
- Dr. Ronald White, Executive Vice President and Senior Consultant of Foster Associates, Inc., will testify in support of proposed new book depreciation rates.
- Mr. Robert Rosenberg, Principal of Edgewood Consulting Inc., will testify about the cost of capital and appropriate capital structure. He is sponsoring certain schedules contained in Section D of the Company's application.
- Mr. John Cogan, Managing Member of The Johnco Group, LLC, will testify regarding proposed changes to the Company's Transportation of Customer-Secured Gas tariff, the AGD's Negotiated Sales Program, and the Company's base cost of gas.
- Mr. James Harrison, Vice President of Management Applications Consulting, Inc., will testify regarding annualized and weather-normalized customer revenues. He will also explain the fully-allocated, embedded customer class cost of service study and his proposed new tariffs, as presented in Sections G and H, respectively.

SUMMARY OF FINANCIAL STATEMENTS

Q. Please describe Schedule A-1 contained in Section A of the Company's application.

A. Schedule A-1 presents the calculation of the increase in gross annual revenues required by the AGD based on the test year ended December 31, 2001. This schedule shows the rate of return on the fair value rate base at present rates. It compares the adjusted test year operating income with the required operating income, computed as the product of the end-of-test-year rate base and the requested rate of return. The resulting operating income deficiency is then converted to the equivalent annual increase in revenues by using the Gross Revenue Conversion Factor.

Q. Please describe Schedule A-2.

A. Schedule A-2 is the Summary Results of Operation. Gross revenues, operating revenue deductions and operating income are shown for the twelve months ended December 31, 1999, December 31, 2000, and for the test year ended December 31, 2001, as recorded. The test year data are shown at present and proposed revenue levels. This information is also presented for the projected year 2002, calculated at present and proposed rates.

Q. What is shown on Schedule A-3?

A. Schedule A-3 is a Summary of Capital Structure, based on Citizens' actual capital structure, for the years 1999, 2000, 2001 and the projected year 2002. That schedule also provides the pro forma capital structure that Mr. Rosenberg has recommended be used in this case. Schedule A-3 further shows the calculation of fair value rate base using an equal weighting of fifty percent for the reproduction costs and original cost components.

Q. Please describe Schedule A-3A.

A. Schedule A-3A, page 1, shows the detail underlying the Citizens capital structure for 1999, 2000, and 2001 set forth on Schedule A-3. Page 2 of that schedule presents the year-end weighted cost rate for Citizens' debt and preferred stock for the years 1999, 2000, 2001 and projected for year 2002. The earned common equity amount (for 1999, 2000, and 2001) shown on that page represents Citizens' <u>achieved</u> net income divided by common equity, and is not a calculated <u>cost</u> of equity consistent with the testimony provided by Mr. Rosenberg.

Q. What information is provided on Schedule A-4?

A. Schedule A-4 presents information concerning the construction expenditures, net plant placed in service and gross utility plant in service for the twelve months ended December 31, 1999 and 2000, and the test year ended December 31, 2001. In addition, construction expenditures, net plant placed in service and gross utility plant in service are projected for the years 2002, 2003 and 2004.

Q. Please describe Schedule A-5 of the Company's application.

A. Schedule A-5 is a Summary of Changes in Financial Position. This information is shown for the twelve months ended December 31, 1999, and December 31, 2000, and for the test year ended December 31, 2001, as recorded. The December 31, 2002, projected data is shown at present and proposed revenue levels.

NET COMMON PLANT ALLOCATION

Q. Has the AGD included a portion of the net common plant for SAO, PSO, LWES or the Phoenix Administrative Office in its request for new rates in this proceeding?

A. No. For this rate proceeding, Citizens has chosen to not seek recognition in rate base (or associated expenses) of the portion of net common plant from these administrative offices relating to the services provided to AGD. As a result, net common plant is not reflected in the plant, accumulated depreciation, or accumulated deferred income taxes components of rate base.

Q. Is this consistent with previous Citizens rate applications and approved Commission treatment?

A. No, it is not. Historically, Citizens has sought and received recovery of a portion of net common plant allocated to the operation under consideration in rate proceedings brought before this Commission. Citizens has chosen to exclude these items from consideration for this rate application in an effort to narrow the focus on the key components of the requested rate increase. Instead, this rate application focuses on the capital investment in plant to extend natural gas facilities to unserved areas and to maintain and improve its existing facilities.

Q. What is the nature of this common plant for these administrative offices?

A. This plant includes office furniture, computers and office equipment that are used in an administrative office for the administrative office personnel to perform their services to operating properties.

Q. How was the net common plant allocated in previous rate proceedings in this jurisdiction?

A. It was allocated using the four-factor allocation, described in my discussion of SAO costs below.

Q. Does Citizens agree, by making this adjustment in this filing, that these items should not be included in rate base or expenses for ratemaking purposes?

A. No it does not. Citizens has been and continues to be of the opinion that net common plant should be included and, correspondingly, should be recovered in rates. These plant assets are necessary and appropriate and are neither extraordinary nor excessive for a typical utility office.

Q. Why then is Citizens voluntarily making this adjustment?

A. The adjustment is offered in an attempt by Citizens to remove from contention items that have a lesser impact on rates, but have in the past required a significant expenditure of human, financial and other resources to support. By eliminating issues, the customers, Citizens, and all parties involved will benefit from this approach.

Q. Does the inclusion of this adjustment mean that Citizens intends to forgo recovery of such plant items in future rate filings?

A. Absolutely not. The adjustment being offered here regarding the net common plant for the identified administrative offices is unique to this filing. It is not meant to waive Citizens' right to include net common plant in any future rate applications in this or any other jurisdiction. Citizens in no way intends to establish any precedent for future filings with respect to the treatment of these plant items.

Q. Has the Company reflected the common plant adjustment made to rate base components in its depreciation expense calculation?

A. Yes, it has. Consistent with the elimination of common plant allocations in rate base, the AGD has excluded depreciation expense for the amounts associated with that plant from this case.

RECONSTRUCTION COST NEW RATE BASE

Q. What is the total adjusted reconstruction cost new less depreciation rate base ("RCN") for the combined AGD at test year-end?

A. The total adjusted RCN rate base for AGD is $190,131,622. As Mr. Doherty explains, Schedule B-3 summarizes the recorded utility plant in service and accumulated depreciation using RCN values. Schedule B-4 lists the original cost and trended RCN value for AGD by each plant account. The original cost for contributions in aid of construction ("CIAC"), advances in aid of construction and the amortization of CIAC have been trended for inclusion in this RCN rate base calculation.

Q. What trending indices are used in establishing the trended RCN values?

A. The Handy-Whitman Indices for Gas Utility Construction, Plateau Region, were used for other production plant, transmission and distribution plant, as well as structures and improvements. For general plant, the Producer Price Index was used.

Q. Have these indices been used in prior rate applications for this and other Citizens' operations before the Commission?

A. Yes. They were used for the two previous NAGD cases and in all other recent Citizens' rate cases for determining the RCN values.

Q. How is the RCN plant amount calculated?

A. The base established for a vintage asset of specific plant account is divided by the corresponding Handy-Whitman valuation index. The result is a trend factor that is multiplied by the original cost of the vintage asset, producing the trended cost consistent with reconstruction cost for that plant new.

Q. Are there elements to the RCN rate base that are not trended?

A. Yes, there are. A detail summary of all the components are found in column 2 of Schedule B-1.

Q. Does the proposed RCN rate base reflect all adjustments ordered in Decision No. 58664 for Original Cost Rate Base ("OCRB") by the Commission?

A. Yes, it does.

AFUDC CALCULATION COMPLIANCE

Q. Please explain the basis for your testimony relating to AFUDC.

A. In conjunction with Docket Nos. E-1032A-94-0139, et. al, Citizens filed a Joint Application for an Order Approving the Accounting Method used to Record an AFUDC. The application sought approval from the Commission of the accounting method used to record an allowance for funds used during construction on IDRBs. As a result of those and related proceedings, Citizens, Staff, and the Residential Utility Consumers Office ("RUCO") reached a Settlement Agreement, which the Commission adopted in Decision No. 61848, dated July 21, 1999. A copy of that Decision has been provided as Exhibit RJM-01, pages 1-14.

Q. What were the terms of the Settlement Agreement?

A. Citizens agreed to use the procedures outlined in the Settlement Agreement for the calculation of AFUDC and for AFUDC in connection with the Federal Energy Regulatory Commission's Release Number 13 ("AR-13 AFUDC") for all of its Arizona utility operations. The Settlement Agreement outlined a ten-step process, with relevant characteristics, for each of the areas/properties identified within the Settlement Agreement. Other procedures for calculating AFUDC in subsequent years described in the Settlement Agreement included:

- Use of a budgeted rate for the ten months of the following year (p. 6, line 10-12);
- Preparation of an initial "true-up" calculation to be used for the months of November and December (p. 6, line 13-16); and
- Performing a final true-up for the previous year by June of each successive year (p. 6, line 18-19).

Additionally, the parties agreed that if the difference between the initial true-up AFUDC and the final AFUDC rate were more than 25 basis points, Citizens would make an adjustment to the financing costs in the final true-up year. If the difference were 25 basis points or fewer, no adjustment would be made.

Q. Did the Settlement Agreement address details of the mechanics of the calculation that are exclusive to AR-13 AFUDC?

A. Yes, it did. The Settlement Agreement provided specific procedures to be used in calculating AR-13 AFUDC. In the copy of Decision No. 61848 provided as Exhibit RJM-01, pages 1-15, these specific procedures can be referenced.

Q. Were there any other conditions in the Settlement Agreement directly pertinent to this rate application?

A. Yes. Citizens agreed that it would provide the Commission, in each of its future rate cases, a comparative calculation showing the AFUDC rates and overall rate of return using short-term debt, as part of the long-term debt component, as compared with using short-term debt as part of the AFUDC calculation.

Q. Has Citizens made such a comparative calculation available for this rate proceeding?

A. Yes it has. Exhibit RJM-01, page 16, provides the required comparison.

Q. Has compliance with this Decision No. 61848 been reflected in this rate application?

A. Yes. Citizens has exceeded the 25 basis points threshold difference between the initial true-up and the final true-up. Correspondingly, it is necessary for an adjustment to be made to the plant basis to reflect the terms of the Settlement Agreement. Mr. Doherty is sponsoring the calculation and proposed rate base adjustment associated with the AR-13

AFUDC.

COMPUTATION OF WORKING CAPITAL

Q. Please describe Schedule B-5.

A. Schedule B-5 summarizes the allowance for working capital requested by the Company in this proceeding. Working capital is a measure of investor funding for daily operating expenditures and non-plant investments that are needed to support ongoing operations. This Schedule consists of three pages, labeled Schedule B-5, Schedule B-5A and Schedule B-5B.

Q. Please explain how working capital requirement on Schedule B-5 was determined.

A. The working capital requirement was determined through a lead/lag study, as required by the Commission for Class A gas utilities the size of AGD.

Q. Does the Company's methodology conform to recommendations of other parties in prior Citizens cases?

A. Yes. The AGD has conformed elements of the lead/lag study to prior Staff lead/lag schedules and recommendations in prior Citizens rate cases in Arizona. For instance, depreciation expense has been excluded from the study and interest expense has been included. The same lag days are shown for rate case expense as were used by Staff in prior Arizona Electric Division and prior Arizona gas cases. The lag days used for interest expense represents an average of the positions presented in prior Citizens Arizona cases by Staff and the Residential Utility Consumer Office.

Q. How did you determine the lead or lag days for other expense items?

A. In order to determine the lead or lag days for other expense items, all invoices were reviewed for the calendar year 2001. Because gas purchases represent a significant portion of total test year expenses, and because Enron ceased to be a supplier to the AGD, the Company sampled invoices from the months of November 2001 through February 2002 for this item. This time period is considered representative of the costs that will be incurred in the first year of new rates.

Q. What is the amount of working capital included in rate base?

A. As shown on line 35 of Schedule B-5, the amount of working capital included in rate base is a negative $2,924,219.

Q. Please describe Schedules B-5A and B-5B.

A. Schedule B-5A shows the reconciliation of expenses for the lead/lag study. Schedule B-5B presents the distribution of the working capital amount among the various cost of service classes.

CARES PROGRAM

Q. Please summarize Schedule B-11.

A. The settlement agreement approved in the last NAGD rate case provided for an annual revenue increase that included an annual $100,000 allowance for Low Income Residential Assistance Programs. As more fully described in the testimony of Mr. Smith, that includes CARES Program discounts and other low-income initiatives. In approving the settlement agreement, Commission Decision No. 59875 provided that Citizens create a special balance sheet account for tracking the program costs and recoveries.

Specifically, as described in Decision No. 59875, beginning at line 18 on page 4, Citizens should "calculate a recovery rate for the Programs by dividing the $100,000 annual allowance by the total test year normalized, annualized sales therms." Using the final adjusted test year sales of 102,040,360 therms in that rate case produces an implied cost recovery rate of $.00098 per therm. All program costs are to be charged to a special balance sheet amount. At the end of each month, the total sales billed are to be multiplied by the cost recovery rate to establish a measure of Program costs billed to ratepayers. The computed amount is to be deducted from the balance sheet account and charged to operating expenses. If customer revenues from the CARES surcharge exceed the low-income program expenses and discounts, the balance sheet account increases.

The rate base element labeled "CARES" represents the cumulative difference between the amount incurred in connection with CARES discounts and other low-income programs and amounts recovered in current service rates since they were implemented in November 1996. Schedule B-11 reflects the development of the required balance in the special tracking account as of the end of the test year. The $364,945 credit balance is identified as a deduction from rate base.

There is a companion adjustment (Schedule C-2, Adjustment Q) relating to the annual pro forma amortization expense level proposed for inclusion in operating expenses.

SALARIES AND WAGES

Q. Please explain the Salaries and Wages calculation.

A. Adjustment B to Schedule C-2 adjusts test year salary and wage expense to reflect an annualized level. It reflects the actual number of active employees plus temporary vacancies (in previously filled positions) existing at the end of the test year. This adjustment was computed using the most current known and measurable salary and wage rates. The computation also reflects an average annual overtime level for the past five years and the actual test year account distribution of payroll expense.

REGULATORY, MISCELLANEOUS AND PER DIEM EXPENSES

Q. Please describe Adjustment D on Schedule C-2.

A. Adjustment D on Schedule C-2, provides a summary of the estimated legal, regulatory, consulting and special studies expenses, as well as miscellaneous and per diem expenses for this filing. These expenses are broken into two groups: (1) the current rate case annual amortization and (2) ongoing amortization of the Build Out Program allowed expense from the last rate case.

Q. Please describe how the amount of rate case expense for this application has been estimated.

A. The basic procedure is the same as the procedure used by Citizens in other cases filed before this Commission. First, after a review of the filing requirements and potential issues in the proceeding, the Company determined subject-matter witnesses and, where necessary, identified and contacted outside consultants. Second, outside consultant cost estimates are made. Third, for the SAO, PSO, and LWES personnel, the Company estimated the travel, lodging, meals, and other out-of-pocket costs required to participate in the rate case proceeding. As in prior cases, all estimates will be replaced with actual charges as soon as the actual charges are available.

Q. Does the rate case expense reflect any salaries and wages costs for any Citizens employees listed on the AGD payroll or charged to AGD from affiliates in other sections of the test year income statement?

A. No. Neither the employees on the payroll of AGD or Citizens affiliates are included in the estimates for rate case expenses. Only the direct (travel, lodging, meals and other out-of-pocket) expenses described previously are being requested concerning internal employees.

Q. Will these estimates be updated as the rate case is processed?

A. Yes. We will update the expenses with supporting documentation and replace the estimates with actual amounts.

Q. Is the AGD proposing to recover the full amount of its estimated rate case expenses?

A. No, it is not. For purposes of this proceeding, I reviewed Commission-authorized rate case expenses for prior Citizens rate cases in Arizona. I used those prior allowances, adjusted for inflation, to derive the rate case expense for which the AGD is seeking recovery in this proceeding. This requested amount is considerably lower than the costs the Company expects to incur, as shown on Adjustment D of Schedule C-2.

Q. What period has been used for the amortization of rate case expense requested in this application?

A. The total requested current rate case expenses of $500,000 have been amortized over a three-year period, as shown in Schedule C-2, resulting in annual amortization of $166,667. This period is consistent with amortization periods in prior Citizens' Arizona rate cases.

Q. Please describe the component of Adjustment D relating to Build Out Program case expenses.

A. In Decision No. 59875, issued October 29, 1996, the Commission authorized the NAGD to amortize case expenses of $125,000 associated with the Build Out Program over a ten-year period. The amount shown in Adjustment D includes one year's amortization of those costs.

INSURANCE EXPENSE

Q. Please describe Adjustment E in Schedule C-2.

A. Adjustment E of Schedule C-2 provides the 2001 recorded test year ending insurance expense for AGD, the pro forma insurance expense, and the resultant pro forma adjustment. Exhibit RJM-02 lists the insurance coverages and details the calculation for each of the pro forma insurance coverages included in the pro forma total. Insurance expense for AGD consists of: (a) all-risk property insurance; (b) comprehensive crime insurance; (c) directors and officers insurance; (d) fiduciary and excess fiduciary insurance; (e) travel accident insurance; (f) bond insurance; and (g) other miscellaneous insurances. The amounts for 2001 reflect actual insurance expense charged to AGD.

Q. How are the specific insurance coverage expenses calculated?

A. The coverages are common to all the regulated operations of Citizens and are negotiated for Citizens in total, or for a specific utility service where appropriate. The expense is apportioned based on a rate per property value amount for all-risk insurance. Expenses for all other insurance coverages are allocated using (i) the number of employees, (ii) the four-factor formula, or (iii) a ratio of the AGD coverage item as a percentage of total item coverage, as appropriate for each type of coverage.

Q. What is the total pro forma insurance expense for the AGD?

A. The total pro forma expense requested in this proceeding for the AGD, as shown on Schedule C-2, is $114,036.

Q. What is the total pro forma insurance expense adjustment?

A. The total pro forma insurance expense adjustment is an increase of $11,255 from the recorded amount.

INJURIES AND DAMAGE EXPENSES

Q. Please explain Adjustment F in Schedule C-2.

A. This adjustment restates recorded expenses for injuries and damages to pro forma levels. Pro forma amounts for comprehensive general liability, general coverage and worker's compensation are based on property specific information, such as number of employees, pro forma salaries and wages, premium liability factors, and the four- factor formula. Schedule C-2, Adjustment F provides the calculation for the pro forma expense.

Q. What is the basis on which the recorded amount is calculated?

A. The year-end 2001 recorded amount for test year-end injuries and damages expenses is based on the allocated portion of the total policy premium for comprehensive general liability and excess general liability. The general coverage insurance is determined at a per customer rate, while the worker's compensation amount is calculated by multiplying a rate based on job classification times the total salaries for that job classification rate per $100 multiple times the estimated percentage increase in the total premium for the coverage. The specific formulas are set forth in Exhibit RJM-03.

Q. What is the total pro forma injuries and damages expense for the AGD?

A. The total pro forma injuries and damages expense requested in this proceeding is $ 282,564. The calculation of this amount is shown on Exhibit RJM-03.

Q. What is the total pro forma injuries and damages expense adjustment?

A. The total pro forma insurance expense adjustment is an increase of $54,158 from the recorded amount.

EMPLOYEE WELFARE AND PENSION BENEFITS EXPENSES

Q. Please describe Adjustment G in Schedule C-2.

A. Adjustment G provides a summary of the employee welfare expense and pension expenses for the pro forma levels. The employee benefits costs consist of: (a) medical and dental benefit; (b) vision care; (c) long-term disability; (d) personal accident insurance; (e) group life insurance; (f) pension benefit; (g) 401K; and (h) the Incentive Deferred Compensation Program ("IDCP"). The pro forma expense of $2,109,756 is an increase from that for the 2001 year-end recorded expense level. The calculation of the expense for each of these benefits is contained in the Exhibit RJM-04.

Q. How much is the total pro forma employee welfare and pension adjustment?

A. The total pro forma employee welfare and pension adjustment is an increase of $369,753 from the recorded level.

STAMFORD ADMINISTRATIVE OFFICE EXPENSE

Q. What is the SAO?

A. The Stamford Administrative Office, located in Stamford, Connecticut, provides essential services to all divisions and subsidiaries of Citizens, mainly by providing oversight and policy guidance for all Citizens' operations. The specific services provided include the following:

- Internal audit
- Corporate & Consolidation accounting
- Financial Reporting
- Tax Accounting
- Information Systems Support
- Risk & Cash Management
- Shareholder & Investment Community Services
- Corporate & Employee Communication
- Human Resource & Employee Benefits Policy Oversight
- Corporate Regulatory
- Corporate Legal
- Financing & Investment Services
- Accounting Policy & Procedures Oversight

Q. What types of expenses are charged to AGD from SAO?

A. SAO expenditures incurred on behalf of divisions and subsidiaries include the following: (a) salaries, payroll taxes, and employee benefits of SAO personnel who provide services to the AGD; (b) rent, taxes, and other costs of operation necessary to support the personnel at the SAO; (c) financing expense, shareholder expense, and directors' fees required for the operations of the corporation; (d) expense for subscriptions, memberships in and dues to professional organizations; (e) legal expenses; (f) travel and per diem expenses relating to each of the above; and (g) insurance.

Q. Please explain the SAO expense calculation.

A. Schedule C-2, Adjustment L, page 2 of 4, provides a summary of the calculation of pro forma SAO expense at test year-end, December 31, 2001. Line 7 provides the corresponding pro forma expense adjustment. Exhibit RJM-05 summarizes the pro forma administrative office expenses to be charged to the AGD for the test year.

Q. What amount of SAO expenses is charged to AGD in the test year?

A. The recorded SAO expense charged to AGD for the test year is $1,148,857. The total pro forma SAO expense distributed to AGD operations is $435,363. Page 2 of Exhibit RJM-05 provides the details of the pro forma calculation.

Q. How were the total SAO expenses distributed to Citizens operations for year ended December 31, 2001?

A. The four-factor formula was used to distribute SAO expenses to operations.

Q. What is the four-factor formula?

A. This formula, developed by the California Public Utilities Commission in the 1950s, is used for charging general administrative items to separate operations. It has been shown to be a reasonable method of distributing general charges. The four-factor formula is a mathematical calculation that results in an average of the relationship of each property to the total properties for four elements: (1) utility plant-in-service; (2) operation and maintenance ("O&M") expense; (3) customers; and (4) payroll charged to O&M. These four categories represent areas of administrative review and oversight performed by SAO or other administrative personnel, and also for common functions. The amounts for each of Citizens' operating divisions and subsidiaries are listed and the percent of each property is determined by dividing the property amount by the total amount for the category. The same process is completed for each of the other three categories and the four percentages are averaged to obtain the four-factor allocator for each specific operating property.

Q. Has the use of the four-factor method been accepted by this Commission and other commissions which regulate Citizens' operating properties?

A. Yes. It has been reviewed many times and accepted in all proceedings over the last 25 years.

Q. How was the pro forma 2001 SAO expense calculation prepared?

A. The SAO expense amount for the test year reflects recorded SAO expenses for the year ending December 31, 2001 with pro forma adjustments. Exhibit RJM-05, page 2, shows the pro forma SAO Costs calculation distributed to AGD, adjusted for the pro forma changes that include previously disallowed items.

Q. What events have made the greatest impact upon the distribution of SAO expenses to AGD since the last rate proceeding?

A. Clearly, Citizens' business strategy to pursue the acquisition of telephone access lines to become a pure telecommunications entity, while seeking to divest of its public services operations, has had the most profound impact on the SAO expenses since the last rate proceeding.

Q. How have the completed acquisitions of telecommunications operations and sales of public service operations affected the calculation of the pro forma SAO expenses charged to AGD?

A. Citizens' strategy to become a telecommunications company has resulted in a significant increase in the number of telecommunications customers served, while the number of public service customers has declined. These changes have greatly impacted the amount of SAO expenses allocated to each operation where the four-factor method of allocation is employed. The current four-factor allocation reflects a significant reduction for all the operations of Citizens that received allocable SAO expenses prior to the close of the announced communications acquisitions by December 2001.

While Citizens also closed on the sale of some public service operations, the impact of the added communications properties more than offset the effect of the sale of those public services properties.

Q. Has this factor been included into the four-factor formula in the pro forma allocated SAO expenses?

A. Yes, I have. Exhibit RJM-05, page 2, shows the 2001 year-end closing pro forma four-factor calculation that reflects the telephone access line acquisitions and the divestitures of public service operations that had closed as of December 31, 2001. That page also reflects adjustments made to remove Griffith operations and other related plant adjustments from the AGD basis.

Q. Have other adjustments been made in preparing the pro forma SAO allocable cost calculation?

A. Yes. I have made adjustments to remove items that have previously been disallowed by the Commission. The items include allocable charges for divestiture efforts, donations and contributions, and other selected expenses. In addition, I have removed some items that have not been denied in previous proceedings but have been of a contentious nature. These adjustments are summarized on page 2 of Exhibit RJM-05.

Q. How is the adjustment calculated and applied to the 2001 SAO expenses?

A. The total amount of 2001 SAO expenses to be removed are identified and then multiplied by the pro forma AGD four-factor to calculate the allocable amount for AGD. This amount is then subtracted from the unadjusted pro forma SAO costs being charged to AGD.

Q. Have you made any additional adjustments to the pro forma SAO expense that you are recommending in this case?

A. Yes. I have adjusted the 2001 test year amounts to reflect actual experience through the first four months of 2002. I derive this adjustment by annualizing the monthly average based on 2002 actuals for the first four months. I then calculated a percentage of annualized 2002 total of the recorded 2001 total SAO expense, and subtracted 100% from that calculated percentage. The resulting percentage was applied to the adjusted 2001 test year total SAO expense for AGD. The amount produced by that calculation represents my adjustment to reflect 2002 actuals.

Q. Is the pro forma SAO expense charged to AGD of $435,363 a reasonable amount?

A. Yes. The pro forma charges from SAO to AGD are reasonable. Performance of certain administrative functions by a central office allows AGD to take advantage of economies of scale that would not otherwise be available. This means service for the customers of Citizens at reduced costs. Moreover, the SAO charges represent a portion of the reasonable and necessary costs that Citizens incurs to operate a publicly-held utility company. The Commission should allow the AGD to recover its share of these legitimate operating expenses.

PSO DISTRIBUTED EXPENSE

Q. What is the PSO?

A. The Public Service Organization, or PSO, is an administrative support office located in Louisiana that provides accounting, management information and engineering services for the PSS of Citizens, which includes all operations and/or properties that provide electric and gas (and previously water and wastewater) services.

Q. Was the same procedure used for the SAO also used to calculate the amount of PSO charges allocated to AGD?

A. Yes, with a slight alteration. Because the services provided by the PSO are exclusive to the public service segment of Citizens' operations, the four-factor formula excludes the telecommunications operations from the pool of operations used in the various factors. The principles and premises that make use of the four-factor method appropriate are the same as discussed earlier.

Q. Have the details of the Public Service four-factor calculation been provided in this testimony?

A. Yes. Exhibit RJM-05, page 3, summarizes the pro forma calculation. This calculation excludes the telecommunications operations and amounts associated with Griffith and the Paulden Line (described in Mr. Doherty's testimony). This resulted in a four-factor formula allocation of 9.65% for AGD as of the end of the test year.

Q. Where are the charges to AGD from PSO provided in the rate filing?

A. The charges for the PSO are included in Schedule C-2, Adjustment L, page 3 of 4. Exhibit RJM-05 provides a summary of the calculation for the $971,292 PSO pro forma amount charged to AGD.

Q. Have you made any additional adjustments to the pro forma PSO expense that you are recommending in this case?

A. Yes. I have adjusted the 2001 test year amounts to reflect actual experience through the first four months of 2002. I derive this adjustment in the same manner discussed in connection with SAO expense.

Q. What future business decisions could partially offset the increase in costs being allocated to each public service operation?

A. A decrease in the size of staff for PSO would reduce costs being allocated, but the magnitude of any such reduction cannot be readily determined at this time.

Q. Is the total pro forma PSO expense of $971,292 charged to AGD a reasonable amount?

A. Yes. The pro forma charges from PSO are reasonable. Using the four-factor formula ensures that each operation, including AGD, supports its fair share of all general PSO expenses.

There is an additional factor supporting the reasonableness of these charges. For the purposes of this rate filing, Citizens has capped the allocable pro forma PSO expenses to an amount that results in a total administrative offices (i.e., SAO, PSO, and LWES) allocated expense distribution that is approximately the same as that approved in the last litigated NAGD rate proceeding. In Decision No. 58664, this amount was approximately $1.2 million. Although that proceeding related only to NAGD, the Company is limiting its request for the whole AGD to that level. The purpose of this proposed expense limit is to facilitate expeditious consideration of this rate application as well as to allow attention to be directed to the key factor for the requested revenue increase in this proceeding, the increase in plant investment.

LWES ORGANIZATION DISTRIBUTED EXPENSE

Q. Are there other administrative groups that support the operation of AGD?

A. Yes. The LWES Organization, previously known as the Dallas Administrative Office ("DAO") provides specific computer support, local area network, intranet management and other information technology-related services to all of Citizens' operations. This organization has relocated to Rochester, New York, and continues to provide similar services to all of Citizens' properties.

Q. How are LWES charges distributed?

A. For those services described, the charges are distributed using the same four-factor formula utilized for SAO, since all of Citizens' operations are beneficiaries of their services.

Q. What is the pro forma amount of LWES expenses?

A. The pro forma amount is $59,423 as shown on page 4 of Schedule C-2, Adjustment L. Exhibit RJM-05, page 4, provides the pro forma calculation that uses the distribution as of December 31, 2001.

Q. Have you made any additional adjustments to the pro forma LWES expense that you are recommending in this case?

A. Yes. I have adjusted the 2001 test year amounts to reflect actual experience through the first four months of 2002. I derive this adjustment in the same manner discussed in connection with SAO expense.

Q. Is the $59,423 LWES pro forma amount reasonable?

A. Yes. The pro forma calculation takes into consideration all the previously described forces that would work to alter AGD's four-factor allocation. As a result, the pro forma amount is significantly less that what has historically been experienced.

CARES DISCOUNT AND EXPENSE

Q. Please explain Adjustment Q, entitled CARES Discount and Expense.

A. Adjustment Q represents the operating expense adjustment that corresponds to the rate base component contained in Schedule B-11. This adjustment is made to reflect a proper test year amortization of the Low Income Residential Assistance Program costs as required under the procedure set forth in Commission Decision No. 59875. It also incorporates the annual effect of changes being proposed to the CARES program and other low-income initiatives, as more fully described in Mr. Smith's testimony.

COST OF CAPITAL

Q. Please describe Schedule D-1.

A. Schedule D-1 shows the test year capital structure and cost of capital based on the recommendations contained in Mr. Rosenberg's testimony. That schedule also shows the fair value rate of return using Mr. Rosenberg's proposed capital structure and cost rates.

Q. What does Schedule D-1A show?

A. Schedule D-1A sets forth Citizens' actual capitalization and capital structure for the test year, as well as the actual cost of preferred securities and long-term debt. The schedule also shows the components of the long-term debt capitalization amount. This information is provided in accordance with the Commission's standard filing requirements. However, the Company is proposing the capital structure and costs based on Mr. Rosenberg's testimony, which is shown on Schedule D-1.

Q. Please describe Schedule D-2A.

A. Schedule D-2A presents the AGD's actual cost of long-term debt. This information is shown in compliance with the Commission's standard filing requirements. However, as Mr. Rosenberg explains, the Company is using a cost of debt based on a group of proxy companies identified in Mr. Rosenberg's testimony.

Q. What is shown on Schedules D-3 and D-3A?

A. The standard filing requirements include a schedule showing the cost of preferred stock. As Mr. Rosenberg states, the capital structure based on his proxy group has no preferred stock. However, for purposes of complying with the Commission's standard filing requirements, Schedule D-3A shows the detailed cost of Citizens' existing preferred stock.

FINANCIAL PROJECTIONS

Q. Please describe briefly what information is contained in Section F of the AGD's rate application.

A. Section F contains Schedules F-1 through F-4. These schedules present financial data for the test year ended December 31, 2001, and the projected year ending December 31, 2002. Schedule F-1 shows income statements for the test year and for the projected year ending December 31, 2002, at present and proposed rates. Schedule F-2 identifies the changes in financial position for the test year and for the projected year at both present and proposed rates. Schedule F-3 lists construction expenditures for the test year ended December 31, 2001, and the projected construction expenditures for calendar years ending 2002, 2003 and 2004. Schedule F-4 provides the assumptions used to develop these Section F projections.

Q. Does this complete your direct testimony?

A. Yes, it does.

1

Exhibit-RJM-1
CCC-AGD
Docket No. G-01032-02-AFUDC

BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED
JUL 21 1999
DOCKETED BY MY

CARL J. KUNASEK
CHAIRMAN
JIM IRVIN
COMMISSIONER
WILLIAM A. MUNDELL
COMMISSIONER

IN THE MATTER OF THE JOINT APPLICATION OF CITIZENS UTILITIES COMPANY, SUN CITY SEWER COMPANY, SUN CITY WATER COMPANY, SUN CITY WEST UTILITIES COMPANY, TUBAC VALLEY WATER COMPANY, CITIZENS WATER RESOURCES COMPANY OF ARIZONA, CITIZENS WATER SERVICES COMPANY OF ARIZONA, ELECTRIC LIGHTWAVE, INC., CITIZENS UTILITIES RURAL COMPANY, INC., CITIZENS TELECOMMUNICATIONS COMPANY OF THE WHITE MOUNTAINS, INC., AND NAVAJO COMMUNICATIONS CO., INC. FOR AN ORDER APPROVING THE ACCOUNTING METHOD USED TO RECORD AN ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION.	DOCKET NO. SW-01032A-94-0139 SW-02276A-94-0139 W-01656A-94-0139 W-02334A-94-0139 W-01595A-94-0139 T-01954A-94-0139 T-03214A-94-0139 T-02115A-94-0139
IN THE MATTER OF THE APPLICATION OF CITIZENS UTILITIES COMPANY, ARIZONA ELECTRIC DIVISION, FOR AN ORDER THAT ALTERS AND AMENDS AND APPROVES THE PROPOSED ACCOUNTING METHOD TO RECORD AN ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION.	DOCKET NO. E-01032A-92-0073 DECISION NO. 61848 **ORDER**

Open Meeting
July 13, 1999
Phoenix, Arizona

FINDINGS OF FACT

1. Citizens Utilities Company ("Citizens" or "the Company") and its Arizona operating divisions and subsidiaries -- Mohave Electric Division, Agua Fria Water Division, Northern Arizona Gas Division, Mohave Wastewater Division, Mohave Water Division, Santa Cruz Gas Division, Sun City Sewer Company, Sun City Water Company, Sun City West Utilities Company, Tubac Valley Water, Inc., Company, Citizens Utilities Rural Company, Inc., Citizens Telecommunications Company of the White Mountains, Inc., and Navajo Communications Company, Inc., Citizens Water Resources Company of Arizona, Citizens Water Services Company of Arizona, and Electric Lightwave, Inc., (collectively referred to herein as "Citizens Arizona Operations"), are Arizona public service corporation(s) engaged in the businesses of providing telecommunications, electric, natural gas, water and wastewater utility service within the State of Arizona, pursuant to Article 15 of the Arizona Constitution.

2. On May 5, 1994, Citizens filed a Joint Application for an Order Approving the Accounting Method used to Record an Allowance for Funds Used During Construction. (Docket Nos. E-1032-94-139, U-2276-94-139, U-1656-94-139, U-2334-94-139 and U-1595-94-139.) The application sought approval from the Arizona Corporation Commission ("Commission") of the accounting method used to record an allowance for funds used during construction ("AFUDC") on Industrial Development Revenue Bonds ("IDRBs").

3. Thereafter, on January 3, 1997, the Commission issued Decision No. 59951, which ordered that all AFUDC on IDRBs be removed from rate base and directing the Hearing Division to issue a Procedural Order regarding the proper AFUDC methodology. On January 22, 1997, Citizens filed an amendment to the application, requesting that all of its Arizona operations be included in the application, including Citizens Telecommunications Company of the White Mountains, Inc. and Navajo Communications Co., Inc.

4. On January 31, 1997, the Commission's Hearing Division issued its Procedural Order to govern the proceedings. The Procedural Order established dates for filing of testimony, discovery guidelines, intervention dates and a hearing date.

5. In conformance with the Procedural Order, and subsequent Procedural Orders, the following events have occurred: RUCO and Sun City Taxpayers Association have applied for and been granted intervention; updated testimony was submitted by the Company on July 10, 1997; Staff submitted direct testimony on December 5, 1997; RUCO submitted direct testimony on December 4, 1997; the Company submitted Rebuttal testimony on December 29, 1997; RUCO submitted surrebuttal testimony on January 8, 1998 and Staff notified the Hearing Officer that it would not be submitting surrebuttal testimony on January 14, 1998.

6. During the pendency of these proceedings, Staff, RUCO and the Company attempted to narrow and resolve the various issues raised by the application. As a result of those discussions, Staff, RUCO and the Company reached a resolution of all issues in the case, as evidenced by the agreement ("Settlement Agreement") between Citizens, Staff and RUCO, dated March 24, 1999, and attached as Exhibit "A."

7. Pursuant to the Settlement Agreement, Staff, RUCO and the Company have agreed to resolve the issues raised in this case on the following terms:

A. Citizens will use the procedures outlined in the Settlement Agreement for the calculation of AFUDC and for AFUDC in connection with the Federal Energy Regulatory Commission's Accounting Release Number 13 ("AR-13 AFUDC") for all of its Arizona utility operations.

B. Citizens will calculate a separate AFUDC rate for each of the following:

i. Santa Cruz County, which includes:

a. Citizens' Santa Cruz Electric Division
b. Citizens' Santa Cruz Gas Division
c. Tubac Valley Water Company

ii. Mohave County, which includes:

a. Citizens' Mohave Electric Division
b. Citizens' Mohave Water Division
c. Citizens' Northern Arizona Gas Division
d. Lake Havasu Water Company

iii. Maricopa County, which includes:

a. Sun City Water Company
b. Sun City Sewer Company
c. Sun City West Utilities Company - Water Operations
d. Sun City West Utilities Company - Wastewater Operations
e. Citizens' Agua Fria Water Division
f. Citizens Water Resources Company of Arizona
g. Citizens Water Services Company of Arizona

iv. Citizens' Northern Arizona Gas Division Operations in:

a. Yavapai County Operations
b. Coconino County Operations
c. Flagstaff Operations
d. Navajo Operations

v. Citizens Utilities Rural Telephone Company, Inc.

vi. Citizens Telephone of the White Mountains

vii. Navajo Communications Company, Inc.

C. The Settlement Agreement sets forth the procedure by which the AFUDC rate will be calculated for each of the areas/properties identified within the Settlement Agreement. A ten-step process is outlined, with the following relevant characteristics:

i. total construction expenditures as the starting amount;

ii. deduction of all customer contributions-in-aid-of-construction ("CIAC") and advances-in-aid-of-construction ("AIAC");

iii. deduction of accounts payable related to construction expenditures that are open at the end of the month of the calculation;

iv. addition or subtraction of accumulated deferred income taxes ("ADIT") related to the construction expenditures;

v. deduction of any other source of capital associated with construction expenditures that is provided at no cost;

vi. the amount resulting from the previous five steps shall be used as the amount of construction expenditures to be financed by Citizens;

vii. the first source of financing shall be property specific financing;

viii. If construction expenditures exceed property specific financing sources, the next source to be applied is pro-rata share of Citizens' average short-term debt. If short-term debt is included in Citizens' capital structure for rate making purposes, this shall be presumed to be zero;

ix. If construction expenditures exceed property specific and short-term debt sources, the remaining amount shall be allocated as long-term debt, preferred stock and common equity in direct proportion to Citizens' most recent year-end capital structure, so that the total sources of funds equals construction expenditures; and

x. financing costs shall equal the sum of the following:

a. Trustee Management Fees;
b. Final true-up adjustment (if necessary);
c. Average rate for property specific debt times amount of property specific debt;
d. Average rate for short-term debt times amount of short-term debt;

e. Average rate for long term debt, times amount of long term debt;

f. Average rate for preferred times amount of preferred equity;

g. Return on Equity ("ROE") used by the Commission in the latest rate case for any Citizens-Arizona operations.

The sum of the financing costs calculated in accordance with the procedure delineated above, divided by the total construction expenditures, will be used to establish the AFUDC rate to be used for each of the properties described in Section B.

D. Citizens will calculate a budgeted AFUDC, rate using the procedures described in Section C, at the end of each year. Citizens will use the budgeted rate for the first ten months of the following year.

E. Citizens will perform an initial "true-up" calculation of its AFUDC rate in November of each year, following the procedures described above; use the rate so calculated for the months of November and December; and adjust the budgeted AFUDC rate from the first ten months of the year to reflect the initial true-up rate.

F. Citizens will perform a final true-up for the previous year by June of each successive year. If the final AFUDC rate is more than 25 basis points different from the AFUDC rate determined at the initial true-up, Citizens will make an adjustment to the financing costs in the final true-up year. If the difference between the initial true-up AFUDC rate and the final AFUDC rate is 25 basis points or fewer, no adjustment shall be made.

G. Citizens will use the AFUDC rate calculated using the procedures described above as the AFUDC rate for its calculation of AR-13 AFUDC.

H. AR-13 AFUDC will be calculated for each of the calculation areas having issued-but-undrawn IDRBs by multiplying the amount of issued-but-undrawn IDRBs times the AR-13 AFUDC rate.

Exhibit-RJM-1
Docket No. G-01032-02-

I. The AR-13 AFUDC calculated using these procedures will be reduced by the earnings on the issued-but-undrawn IDRBs as reported by the IDRB Trustee.

J. The net of the AR-13 AFUDC calculated in Section I shall be recorded as part of the issuance costs of the IDRBs, amortized over the life of the IDRB, and included with interest expense in establishing the average annual interest rate for the IDRB.

K. Citizens will use the cost of debt rate, including the amortization of the net AR-13 AFUDC amount in Section J, as the cost of debt in its AFUDC calculations and in its calculations of weighted debt costs in rate of return calculation.

L. Citizens will include 100% of the issued and outstanding IDRBs as part of its long-term debt used in the calculation of the AFUDC rates and in its capital structure used in rate of return calculations.

M. Citizens will provide the Commission, in each of its future rate cases, a comparative calculation showing AFUDC rates and overall rate of return using short-term debt as part of the long-term debt component as compared to using short-term debt as part of the AFUDC calculation.

N. Citizens will conform the use of short-term debt, currently included as part of the long-term debt component of the capital structure, to the treatment ordered by the Commission in future orders. The conformance will be performed for all properties within an operational area as defined in Section B, whenever a Commission order affects any of the operating entities within the defined area.

8. Citizens, RUCO and Staff all agree that the procedures described in the Settlement Agreement will result in fair and equitable treatment of the calculation of AFUDC and the use of property specific financing, including IDRBs, and recommend approval by the Commission.

CONCLUSIONS OF LAW

1. Citizens and its operating divisions and subsidiaries are public service corporations within the meaning of Article 15 of the Arizona Constitution.

2. The Commission has jurisdiction over Citizens and its operating divisions and subsidiaries, over the subject matter of these proceedings and over the Settlement Agreement submitted by the Staff, Citizens and RUCO.

3. The Settlement Agreement between Staff, Citizens and RUCO resolves all the issues pending in the dockets referenced in the caption of these proceedings in a manner which is just and reasonable, and which promotes the public interest.

4. The Commission's acceptance of the Settlement Agreement between Staff, Citizens and RUCO is in the public interest.

ORDER

IT IS THEREFORE ORDERED approving the Settlement Agreement executed March 24, 1999, among Staff, Citizens and RUCO and directing the parties to abide by the terms of the Settlement Agreement.

IT IS FURTHER ORDERED that this Order shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION

CHAIRMAN **COMMISSIONER** **COMMISSIONER**

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 21st day of July, 1999.

Brian C. McNeil
Executive Secretary

DISSENT__________

DECISION NO. 61848

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CCC-AGD
Docket No. G-01032-02-
AFUDC

CITIZENS UTILITIES COMPANY
ARIZONA OPERATIONS
CALCULATION OF A.F.U.D.C. AND "AR-13" A.F.U.D.C.

AGREEMENT BETWEEN CITIZENS, STAFF AND RUCO
Docket No. E-1032-94-139 et. al.

Citizens Utilities Company ("Citizens"), the Arizona Corporation Commission Staff ("Staff") and the Residential Utility Consumers Office ("RUCO") (collectively the "Parties") have agreed to the procedures to be used in the calculation of the allowance for funds used during construction ("AFUDC") for all of Citizens' operating divisions and subsidiaries providing utility services in the State of Arizona ("Citizens-Arizona") under the jurisdiction of the Arizona Corporation Commission ("Commission). In addition, the parties are in agreement on the procedures for the calculation of AFUDC on issued-but-undrawn, special purpose, property-specific bonds, such as Industrial Development Revenue Bonds ("IDRBs") and Rural Telephone Bank loans ("RTB"). These procedures reflect those contained in the Federal Energy Regulatory Commission's ("FERC") Accounting Release, Number 13 ("AR-13").

This Agreement reflects the Parties' mutual desire to develop fair and equitable procedures for determining AFUDC, in a manner consistent with the public interest. This Agreement is based upon careful review of the prefiled testimony and exhibits filed in this docket, and months of discussions among the Parties. This Agreement will be submitted for the review and approval by the Commission.

AGREED-UPON PROCEDURES

A. Citizens will use the procedures set forth in this Agreement for the calculation of AFUDC and AR-13 AFUDC for all of its Arizona utility operations;

B. Citizens-Arizona will calculate a separate AFUDC rate for each of the following:

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1) SANTA CRUZ COUNTY, which includes:
- Citizens' Santa Cruz Electric Division;
- Citizens' Santa Cruz Gas Division; and
- Tubac Valley Water Company.

2) MOHAVE COUNTY, which includes:
- Citizens' Mohave Electric Division;
- Citizens' Mohave Water Division;
- Citizens' Northern Arizona Gas Division, and
- Lake Havasu Water Company.

3) MARICOPA COUNTY, which includes:
- Sun City Water Company;
- Sun City Sewer Company;
- Sun City West Utilities Company-Water Operations;
- Sun City West Utilities Company-Wastewater Operations;
- Citizens' Agua Fria Water Division;
- Citizens Water Resources Company of Arizona; and
- Citizens Water Services Company of Arizona.

4) CITIZENS' NORTHERN ARIZONA GAS DIVISION, which includes:
- Yavapai County Operations;
- Coconino County Operations;
- Flagstaff Operations; and
- Navajo Operations.

5) CITIZENS UTILITIES RURAL TELEPHONE COMPANY, INC.
6) CITIZENS TELEPHONE OF WHITE MOUNTAINS
7) NAVAJO COMMUNICATIONS COMPANY, INC.

C. The AFUDC rate shall be calculated for each of the seven areas/properties ("calculation areas") identified in section (B) above using the following procedures:

1. Citizens will use the total construction expenditures as the starting amount;
2. Citizens will deduct all customer contributions-in-aid-of-construction ("CIAC") and customer advances-in-aid-of-construction ("AIAC") from the construction expenditures identified in section (C)(1);
3. Citizens will deduct the accounts payable related to construction expenditures that are open at the end of the month that the AFUDC calculation is made;
4. Citizens will add or deduct the amount of accumulated deferred income taxes ("ADIT") related to the construction expenditures identified in section (C)(1);
5. Citizens will deduct any other source of capital associated with the construction expenditures in section (C)(1) that is provided to Citizens at no cost;
6. Citizens will use the amount resulting from the calculations following the procedures set forth in section (C)(1) through (C)(5) as the amount of construction expenditures to be financed by Citizens' sources ("net construction expenditures");
7. Citizens will first determine the amount of property specific financing that is available for the construction expenditures identified in section (C)(1) and apply those funds as the first source of financing;
8. If net construction expenditures exceed the property specific financing source, Citizens will then apply the property's pro-rata share of Citizens' average short-term debt amount as the second source of financing. In the event that the Commission used short-term debt as part of the capital structure in determination of the rates in the last rate, this amount would be zero;

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AFUDC

9. If net construction expenditures exceed the property specific and short-term debt financing sources, Citizens will allocate the remaining amount to be funded to long-term debt, preferred stock and common equity in direct proportion to the capital structure of Citizens at the end of the preceding calendar year. The total amount for the source of funds will be equal to the amount of net construction expenditures to be financed by Citizens' sources;

10. Citizens will calculate the financing costs as the sum of:

(a) Trustee Management Fees;

(b) Final true-up adjustment from prior-year (if necessary—see Section E);

(c) Average rate for property specific debt times amount of property specific debt;

(d) Average rate for short-term debt times amount of short-term debt;

(e) Average rate for long term debt times amount of long term debt;

(f) Average rate for preferred equity times amount of preferred equity; and

(g) Return on equity ("ROE") used by the Commission in the latest Citizens' rate case for any of the Citizens-Arizona operations.

11. Citizens will add the financing costs calculated pursuant to section (C)(10) above, and divide that total amount by the total construction expenditures to determine the AFUDC rate to be used for the properties included in each of the areas identified in section (B).

D. Citizens will calculate a budgeted AFUDC rate following the procedures set forth in section (C) at the end of each year, and will use that budgeted AFUDC rate for the first ten months of the following year.

E. Citizens will perform an initial "true-up" calculation of its AFUDC rate in November of each year, following the procedures set forth in section (C).

Citizens will use that new rate for the months of November and December. Citizens will use the true-up AFUDC rate to adjust the AFUDC calculated using the budgeted AFUDC rate for the first ten months the year. The resulting AFUDC recorded for the year will therefore be based on the AFUDC rate calculated at the initial true up.

F. Citizens will perform a final true up by the end of June of the following year, and will calculate an AFUDC rate using the procedures in set forth in section (C) and the actual data for the entire year. If the final AFUDC rate is more than 25 basis points different from the AFUDC rate determined at the initial true-up, Citizens will make an adjustment to the financing costs in the final true-up year. The true up will reflect the difference between the initial true-up AFUDC rate and the final true-up AFUDC rate. In the event that the difference between the initial true-up AFUDC rate and the final true-up AFUDC rate is equal to or less than 25 basis points, no adjustment will be made and the AFUDC recorded for the prior year will be final.

G. Citizens will use the AFUDC rate calculated using the procedures set forth in section (C) as the AFUDC rate for its calculation of AR-13 AFUDC.

H. AR-13 AFUDC shall be calculated for each of the calculation areas having issued-but-undrawn IDRBs by multiplying the amount of issued-but-undrawn IDRBs times the AR-13 AFUDC rate on a monthly basis.

I. The AR-13 AFUDC calculated using the procedures set forth in section (H) will be reduced by the earnings on the issued-but-undrawn IDRB funds reported by the IDRB Trustee ("net AR-13 AFUDC").

J. The net AR-13 AFUDC calculated pursuant to section (I) will be recorded as part of the issuance costs of the IDRBs, amortized over the remaining life of the IDRB, and included with interest expense in establishing the average annual interest rate for the IDRB.

K. Citizens will use the cost of debt rate, including the amortization of the net AR-13 AFUDC amount as described in section (J), as the cost of debt in its AFUDC calculations and in its calculations of weighted debt costs in the rate of return calculations.

 DECISION NO. 61848

L. Citizens will include one-hundred percent of the issued and outstanding IDRBs as part of its long-term debt used in the calculation of the AFUDC rates and in its capital structure used in rate of return calculations.

M. Citizens agrees to provide the Commission, in each of Citizens' future rate cases, a comparative calculation showing the AFUDC rate and the overall rate of return:

[1] Using the short-term debt as part of the long-term debt component; and

[2] Using the short-term debt as part of the AFUDC rate calculation.

N. Citizens agrees to conform the use of short-term debt, currently included as part of the long-term debt component of the capital structure, to any future Commission order that requires Citizens to utilize a different approach. This change will be made for all of Citizens' Arizona properties within the calculation area if one of the operating properties within the AFUDC calculation area is impacted by the Commission's order.

O. <u>It is the intent of the Parties that this Agreement sets forth the procedures to satisfy the requirement of the Commission Decision No. 58360 that ordered Citizens to submit documentation to Staff on an annual basis to demonstrate its compliance with AR3 (17) and AR-13, for 1997. The Company shall submit documentation to Staff for 1998 by April 30, 1999, and follow the procedures in this Agreement for future periods.</u>

P. The Parties agree that this Agreement constitutes a resolution of all outstanding issues pending in Docket No. E-1032-94-139 et. al. In the event that this Agreement is not accepted by the Commission, none of the Parties herein compromise or otherwise waive the positions they have taken on any of the issues addressed in their prefiled testimony.

Exhibit-RJM-1
CCC-AGD
Docket No. G-01032-02-
AFUDC

Q. The provisions of this Agreement are not severable and shall become effective only after the Commission shall have entered an order approving this Agreement without modification. In the event this Agreement is not approved by the Commission in the form submitted, it shall be deemed withdrawn, and the stipulations contained herein shall be void.

The Parties agree that the above procedures will result in fair and equitable treatment for the Company and its customers related to the calculation of AFUDC and the use of IDRBs and other property specific financing and urge the Commission to approve this Agreement.

DATED this 24th day of March, 1999.

Citizens Utilities Company
By: Craig A. Marks
Title: Associate General Counsel

Staff of the Arizona Corporation Commission
By: RAY T. WILLIAMSON
Title: ACTING DIRECTOR

Residential Utility Consumer Office
By: Barbara Wytaske
Title: Deputy Director

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EXHIBIT-RJM-1
CCC-AGD
Docket No. G-01032-02-
AFDUC Calc

		CITIZENS UTILITIES COMPANY						23-Apr-03	
		TOTAL MOHAVE						12:01 PM	
		CALCULATION OF AFUDC RATE							
			2001						
			(A)	(B)	(C)	(D)		(E)	
LINE NO.	ITEM							AMOUNT	
1.)	CONSTRUCTION EXPENDITURES							$15,615,967	
2.)	ADVANCES AND CIAC / NET OF REFUNDS							(623,265)	
3.)	ACCOUNTS PAYABLE RELATED TO CWIP							(961,233)	
4.)	TAX ON ADVANCES AND CIAC							353,100	
5.)	CONSTRUCTION EXP LESS ADV & CIAC							14,384,569	
6.)	DEFERRED INCOME TAXES (CURRENT YEAR DURING CONSTRUCTION)							(684,646)	
7.)	EST.CONSTR.EXPENDITURES							13,699,923	
	SOURCES OF FINANCING								
8.)	IDRB 1993-1997 VARIABLE & FIXED RATE							0	
9.)	ALLOCATED SHORT TERM DEBT							0	[5]
10.)	CORPORATE CAPITAL STRUCTURE							13,699,923	[1]
	TOTAL FINANCING								
11.)	TOTAL SOURCES OF FINANCING							$13,699,923	
	COST OF FINANCING								
12.)	IDRB 1993-1997 VARIABLE & FIXED RATE		0.00%	x	0	=		-	[2]
13.)	ALLOCATED SHORT TERM DEBT		0.00%	x	0	=		-	[2]
14.)	TRUSTEE FEES							33,300	
15.)	SUBTOTAL							33,300	
			ACTUAL RATE	NET OF TAX	ALLOCATED CORP. CAPITAL STRUCTURE	ALLOCATED AMOUNT			
16.)	DEBT(CORPORATE)		7.69%	5.00%	61.479%	8,422,629		420,801	[3]
17.)	PREFERRED STOCK (CORPORATE)		5.25%	3.41%	4.035%	552,794		18,864	[3]
18.)	EQUITY (PROPERTY SPECIFIC) RATE=		10.70%	10.70%	34.486%	4,724,501		505,522	[3]
19.)	SUBTOTAL		23.64%	19.11%	100.000%	13,699,923		945,187	
				[4]		[1]			
20.)	TRUE-UP ADJUSTMENT FROM PRIOR YEAR							2,317	
21.)	TOTAL COST OF FINANCING							$ 980,804	
22.)	**AFUDC RATE (TOTAL COST OF FINANCING / CONSTRUCTION EXPEND.)**							**6.28%**	
23.)	**MAXIMUM RATE = FERC RATE =**		**6.24%**		**RATE TO BE USED**			**6.24%**	
	[2] Source of Financing x rate (col. A)								
	[3] COL. (B) x (D) = (E)	[4] NET OF TAX 65% x COL (A)			[5] Included as part of Capital Structure				

CITIZENS UTILITIES COMPANY

TOTAL SANTA CRUZ

CALCULATION OF AFUDC RATE

2001

23-Apr-03
12:01 PM

LINE NO.	ITEM	(A)	(B)	(C)	(D)	(E) AMOUNT	
1.)	CONSTRUCTION EXPENDITURES					$3,160,030	
2.)	ADVANCES AND CIAC / NET OF REFUNDS					(1,695,677)	
3.)	ACCOUNTS PAYABLE RELATED TO CWIP					(233,986)	
4.)	TAX ON ADVANCES AND CIAC					691,344	
5.)	CONSTRUCTION EXP LESS ADV & CIAC					1,921,711	
6.)	DEFERRED INCOME TAXES (CURRENT YEAR DURING CONSTRUCTION)					(235,990)	
7.)	EST.CONSTR.EXPENDITURES					1,685,721	
	SOURCES OF FINANCING						
8.)	NO CURENT OUTSTANDING IDRB LOAN					0	
9.)	ALLOCATED SHORT TERM DEBT					0	[5]
10.)	CORPORATE CAPITAL STRUCTURE					1,685,721	[1]
	TOTAL FINANCING						
11.)	TOTAL SOURCES OF FINANCING					$ 1,685,721	
	COST OF FINANCING						
12.)	NO CURENT OUTSTANDING IDRB LOAN	0.00%	x	0	=	-	[2]
13.)	ALLOCATED SHORT TERM DEBT	0.00%	x	0	=	-	[2]
14.)	TRUSTEE FEES					17,550	
15.)	SUBTOTAL					17,550	
		ACTUAL RATE	NET OF TAX	ALLOCATED CORP. CAPITAL STRUCTURE	ALLOCATED AMOUNT		
16.)	DEBT(CORPORATE)	7.69%	5.00%	61.479%	1,036,371	51,778	[3]
17.)	PREFERRED STOCK (CORPORATE)	5.25%	3.41%	4.035%	68,019	2,321	[3]
18.)	EQUITY (PROPERTY SPECIFIC) RATE=	10.70%	10.70%	34.486%	581,331	62,202	[3]
19.)	SUBTOTAL	23.64%	19.11%	100.000%	1,685,721	116,302	
			[4]		[1]		
20.)	TRUE-UP ADJUSTMENT FROM PRIOR YEAR					(32,774)	
21.)	TOTAL COST OF FINANCING					$ 101,078	
22.)	**AFUDC RATE (TOTAL COST OF FINANCING / CONSTRUCTION EXPEND.)**					**3.20%**	
23.)	**MAXIMUM RATE = FERC RATE =**	**6.24%**		**RATE TO BE USED**		**3.20%**	

[2] Source of Financing x rate (col. A)
[3] COL. (B) x (D) = (E)
[4] NET OF TAX 65% x COL (A)
[5] Included as part of Capital Structure

CITIZENS UTILITIES COMPANY

TOTAL NORTHERN ARIZONA GAS

CALCULATION OF AFUDC RATE

23-Apr-03
12:01 PM

LINE NO.	ITEM	(A) 2001	(B)	(C)	(D)	(E) AMOUNT	
1.)	CONSTRUCTION EXPENDITURES					$24,088,779	
2.)	ADVANCES AND CIAC / NET OF REFUNDS					(1,202,943)	
3.)	ACCOUNTS PAYABLE RELATED TO CWIP					(2,383,718)	
4.)	TAX ON ADVANCES AND CIAC					732,639	
5.)	CONSTRUCTION EXP LESS ADV & CIAC					21,234,757	
6.)	DEFERRED INCOME TAXES (CURRENT YEAR DURING CONSTRUCTION)					(277,100)	
7.)	EST.CONSTR.EXPENDITURES					20,957,657	
	SOURCES OF FINANCING						
8.)	IDRB 1997 VAR. & FIXED AZ					0	
9.)	ALLOCATED SHORT TERM DEBT					0	[5]
10.)	CORPORATE CAPITAL STRUCTURE					20,957,657	[1]
	TOTAL FINANCING						
11.)	TOTAL SOURCES OF FINANCING					$ 20,957,657	
	COST OF FINANCING						
12.)	IDRB 1993-1997 VARIABLE RATE	0.00%	x	0	=	-	[2]
13.)	ALLOCATED SHORT TERM DEBT	0.00%	x	0	=	-	[2]
14.)	TRUSTEE FEES					32,000	
15.)	SUBTOTAL					32,000	
		ACTUAL RATE	NET OF TAX	ALLOCATED CORP. CAPITAL STRUCTURE	ALLOCATED AMOUNT		
16.)	DEBT(CORPORATE)	7.69%	5.00%	61.479%	12,884,639	643,727	[3]
17.)	PREFERRED STOCK (CORPORATE)	5.25%	3.41%	4.035%	845,644	28,858	[3]
18.)	EQUITY (PROPERTY SPECIFIC) RATE=	10.70%	10.70%	34.486%	7,227,374	773,329	[3]
19.)	SUBTOTAL	23.64%	19.11%	100.000%	20,957,657	1,445,914	
			[4]		[1]		
20.)	TRUE-UP ADJUSTMENT FROM PRIOR YEAR					(47,542)	
21.)	TOTAL COST OF FINANCING					$ 1,430,372	
22.)	**AFUDC RATE (TOTAL COST OF FINANCING / CONSTRUCTION EXPEND.)**					**5.94%**	
23.)	**MAXIMUM RATE = FERC RATE =**	**6.24%**		**RATE TO BE USED**		**5.94%**	

[2] Source of Financing x rate (col. A)

[3] COL. (B) x (D) = (E)

[4] NET OF TAX 65% x COL (A)

[5] Included as part of Capital Structure

CITIZENS UTILITIES COMPANY
TOTAL ARIZONA SHOWLOW
CALCULATION OF AFUDC RATE
2001

23-Apr-03
12:01 PM

LINE NO.	ITEM	(A)	(B)	(C)	(D)	(E) AMOUNT	
1.)	CONSTRUCTION EXPENDITURES					$8,022,436	
2.)	ADVANCES AND CIAC / NET OF REFUNDS					526,626	
3.)	ACCOUNTS PAYABLE RELATED TO CWIP					(322,581)	
4.)	TAX ON ADVANCES AND CIAC					236,373	
5.)	CONSTRUCTION EXP LESS ADV & CIAC					8,462,854	
6.)	DEFERRED INCOME TAXES (CURRENT YEAR DURING CONSTRUCTION)					(13,440)	
7.)	EST.CONSTR.EXPENDITURES					8,449,414	
	SOURCES OF FINANCING						
8.)	IDRB					0	
9.)	ALLOCATED SHORT TERM DEBT					0	[5]
10.)	CORPORATE CAPITAL STRUCTURE					8,449,414	[1]
	TOTAL FINANCING						
11.)	TOTAL SOURCES OF FINANCING					$ 8,449,414	
	COST OF FINANCING						
12.)	IDRB	0.00%	x	0	=	-	[2]
13.)	ALLOCATED SHORT TERM DEBT	0.00%	x	0	=	-	[2]
14.)	TRUSTEE FEES					-	
15.)	SUBTOTAL					-	
		ACTUAL RATE	NET OF TAX	ALLOCATED CORP. CAPITAL STRUCTURE	ALLOCATED AMOUNT		
16.)	DEBT(CORPORATE)	7.69%	5.00%	61.479%	5,194,648	259,529	[3]
17.)	PREFERRED STOCK (CORPORATE)	5.25%	3.41%	4.035%	340,935	11,634	[3]
18.)	EQUITY (PROPERTY SPECIFIC) RATE=	12.50%	12.50%	34.486%	2,913,831	364,229	[3]
19.)	SUBTOTAL	25.44%	20.91%	100.000%	8,449,414	635,392	
			[4]		[1]		
20.)	TRUE-UP ADJUSTMENT FROM PRIOR YEAR					(4,842)	
21.)	TOTAL COST OF FINANCING					$ 630,550	
22.)	**AFUDC RATE (TOTAL COST OF FINANCING / CONSTRUCTION EXPEND.)**					**7.86%**	
23.)	**MAXIMUM RATE = FERC RATE =**	**6.24%**		**RATE TO BE USED**		**6.24%**	

[2] Source of Financing x rate (col. A)
[3] COL. (B) x (D) = (E) [4] NET OF TAX 65% x COL (A) [5] Included as part of Capital Structure

2

ARIZONA GAS DIVISION
Insurance Expense
For the Pro Forma TEST YEAR @ December 31, 2001

Line #			
	ALL RISK INSURANCE		
A. 1.	ACTUAL Consolidated CITIZENS Gross Plant @ 12/31/01	$	8,687,201,266
2.	All Risk / Property Insurance Allocable Premium - Actual @ 12/31/01	$	3,134,389
3.	AGD ALL RISK Premium Factor - Actual @12/31/01 (AGD - Ins Prop Values '01 /Total '01 CITIZENS Ins Prop Values)		2.790%
4.	AGD - All Risk Insurance Expense - Actual @12/31/01 (Line 2 * Line 3)	$	87,450
5.	AGD - All Risk Insurance Expense Y-T-D Actual @04/30/02	$	28,869
6.	AGD - Pro Forma Annualized All Risk Insurance Expense (Line 5 * 3)	$	86,608
7.	AGD - Pro Forma ALL RISK INSURANCE EXP Adjustment (Line 6 - Line 4)	**$**	**(842)**
	COMPREHENSIVE CRIME		
B. 1.	Consolidated CITIZENS - Comp CRIME Insurance Exp/Premium - Actual @12/31/01	$	31,600
2.	AGD - Comp CRIME Premium Factor - Actual @12/31/01 (AGD # of Employees @ 12/31/01 /Total CITIZENS Employee@12/31/01)		1.93%
3.	AGD - Comp CRIME Insurance Exp - Actual @12/31/01 (Line 1* Line 2)	$	610
4.	AGD - Comp CRIME Insurance Exp Y-T-D Actual @04/30/02	$	593
5.	AGD - Pro Forma Annualized Comp CRIME Insurance Expense (Line 5 * 3)	$	1,779
6.	AGD - Pro Forma COMPREHENSIVE CRIME INSURANCE EXP Adjustment (Line 3 - Line 5)	**$**	**1,169**
	TRAVEL ACCIDENT INSURANCE		
C. 1.	Consolidated CITIZENS - TRAVEL Insurance Exp/Premium - Actual @12/31/01	$	21,423
2.	AGD - TRAVEL Premium Factor - Actual @12/31/01 (AGD # of Employees @ 12/31/01 /Total CITIZENS Employee@12/31/01)		1.93%
3.	AGD - TRAVEL Insurance Exp - Actual @12/31/01 (Line 1* Line 2)	$	413
4.	AGD - TRAVEL Insurance Exp Y-T-D Actual @04/30/02	$	191
5.	AGD - Pro Forma Annualized TRAVEL Insurance Expense (Line 5 * 3)	$	573
6.	AGD - Pro Forma TRAVELINSURANCE EXP Adjustment (Line 3 - Line 5)	**$**	**160**

ARIZONA GAS DIVISION
Insurance Expense
For the Pro Forma TEST YEAR @ December 31, 2001

Line #

MISCELLANEOUS COVERAGES*

D. 1. CITIZENS - MISC Insurance Premium on Common Coverage - Actual @12/31/01 — $ 82,290

2. AGD - MISC Insurance Premium Factor on Common Coverage- BDGTED '2001 — 3.19%
(AGD Participation Factor Budget '2001 /Total CITIZENS MISC Distribution Budget '2001)

3. AGD - MISC Insurance Exp on Common Coverage - Actual @12/31/01 — $ 2,626
(Line 1* Line 2)

* MISCELLANEOUS Coverage includes: Other Misc & Special Coverage

	Total Misc	Special	Other Misc	Surety
	82,290	2,760	11,010	68520
AGD %:	3.191%	1.93%	1.93%	3.44%
AGD Charge:	2,626	53	212	2,360

4. AGD - MISC Insurance Exp Y-T-D Actual @04/30/02 — $ 1,997

5. AGD - Pro Forma Annualized Misc Insurance Expense — $ 5,992
(Line 4 * 3)

6. AGD - Pro Forma MISC INSURANCE EXP Adjustment — **$ 3,366**
(Line 3 - Line 5)

DIRECTORS & OFFICERS (D&O) / Fiduciary

E. 1. CITIZENS - D&O/Fiduciary Insurance Exp/Premium - Actual @12/31/01 — $ 596,680

2. AGD - D&O/Fiduciary Insurance Premium Factor - Actual @12/31/01 — 1.93%
(AGD # of Employees Budget '2001 /Total CITIZENS Employees Budget '2001)

3. AGD - D&O/Fiduciary Insurance Exp - Actual @12/31/01 — $ 11,516
(Line 1* Line 2)

4. AGD - D&O/Fiduciary Insurance Exp Y-T-D Actual @04/30/02 — $ 6,358

5. AGD - Pro Forma Annualized D&O/Fiduciary Insurance Expense — $ 19,073
(Line 4 * 3)

6. AGD - Pro Forma D&O/Fiduciary INSURANCE EXP Adjustment — **$ 7,557**
(Line 5 - Line 3)

F. 1. AGD Natural Account to FERC Adjustment for INSURANCE Exp @ 12/31/01 — $ 166

2. AGD Natural Account to FERC Pro Forma Adjustment for INSURANCE Exp — $ 11

G. 1.	**Total AGD - INSURANCE EXPENSE @ 12/31/01** (Line A4 + Line B3 + Line C3 + Line D3 + Line E3 + Line F1)	**$**	**102,781**
2.	**Total AGD - Pro Forma INSURANCE EXPENSE Adjustment** (Line A7 + Line B6 + Line C6 + Line D6 + Line E6 + F2)	**$**	**11,255**
3.	**Total AGD - Pro Forma INSURANCE EXPENSE** (Line G1 + Line G2)	**$**	**114,036**

Exhibit-RJM-02
CCC-NAGD
Docket No. G-01032A-02-
Insurance Expense

NORTHRN ARIZONA GAS DIVISION
Insurance Expense
For the Pro Forma TEST YEAR @ December 31, 2001

Line #		
	ALL RISK INSURANCE	
A. 1.	ACTUAL Consolidated CITIZENS Gross Plant @ 12/31/01	$ 8,687,201,266
2.	All Risk / Property Insurance Allocable Premium - Actual @ 12/31/01	$ 3,134,389
3.	NAGD ALL RISK Premium Factor - Actual @12/31/01 (NAGD - Ins Prop Values '01 /Total '01 CITIZENS Ins Prop Values)	2.640%
4.	NAGD - All Risk Insurance Expense - Actual @12/31/01 (Line 2 * Line 3)	$ 82,748
5.	NAGD - All Risk Insurance Expense Y-T-D Actual @04/30/02	$ 27,350
6.	NAGD - Pro Forma Annualized All Risk Insurance Expense (Line 5 * 3)	$ 82,051
7.	NAGD - Pro Forma ALL RISK INSURANCE EXP Adjustment (Line 6 - Line 4)	**$ (697)**
	COMPREHENSIVE CRIME	
B. 1.	Consolidated CITIZENS - Comp CRIME Insurance Exp/Premium - Actual @12/31/01	$ 31,600
2.	NAGD - Comp CRIME Premium Factor - Actual @12/31/01 (NAGD # of Employees @ 12/31/01 /Total CITIZENS Employee@12/31/01)	1.860%
3.	NAGD - Comp CRIME Insurance Exp - Actual @12/31/01 (Line 1* Line 2)	$ 588
4.	NAGD - Comp CRIME Insurance Exp Y-T-D Actual @04/30/02	$ 575
5.	NAGD - Pro Forma Annualized Comp CRIME Insurance Expense (Line 4 * 3)	$ 1,725
6.	NAGD - Pro Forma COMPREHENSIVE CRIME INSURANCE EXP Adjustment (Line 5 - Line 3)	**$ 1,137**
	TRAVEL ACCIDENT INSURANCE	
C. 1.	Consolidated CITIZENS - TRAVEL Insurance Exp/Premium - Actual @12/31/01	$ 21,423
2.	NAGD - TRAVEL Premium Factor - Actual @12/31/01 (NAGD # of Employees @ 12/31/01 /Total CITIZENS Employee@12/31/01)	1.86%
3.	NAGD - TRAVEL Insurance Exp - Actual @12/31/01 (Line 1* Line 2)	$ 398
4.	NAGD - TRAVEL Insurance Exp Y-T-D Actual @04/30/02	$ 185
5.	NAGD - Pro Forma Annualized TRAVEL Insurance Expense (Line 4 * 3)	$ 555
6.	NAGD - Pro Forma TRAVELINSURANCE EXP Adjustment (Line 5 - Line 3)	**$ 157**

NORTHRN ARIZONA GAS DIVISION
Insurance Expense
For the Pro Forma TEST YEAR @ December 31, 2001

Exhibit-RJM-02
CCC-NAGD
Docket No. G-01032A-02-
Insurance Expense

Line #

MISCELLANEOUS COVERAGES*

D. 1. CITIZENS - MISC Insurance Premium on Common Coverage - Actual @12/31/01 — $82,290

2. NAGD - MISC Insurance Premium Factor on Common Coverage- BDGTED '2001 — 2.98%
(NAGD Participation Factor Budget '2001 /Total CITIZENS MISC Distribution Budget '2001)

3. NAGD - MISC Insurance Exp on Common Coverage - Actual @12/31/01 — $ 2,449
(Line 1* Line 2)

* MISCELLANEOUS Coverage includes: Other Misc & Special Coverage

	Total Misc	Special	Other Misc	Surety
	$ 82,290	$ 2,760	$ 11,010	$ 68,520
NAGD %:	2.976%	1.860%	1.860%	3.201%
NAGD Charge:	$ 2,449	$ 51	$ 205	$ 2,193

4. NAGD - MISC Insurance Exp Y-T-D Actual @04/30/02 — $ 1,896

5. NAGD - Pro Forma Annualized Misc Insurance Expense — $ 5,689
(Line 4 * 3)

6. NAGD - Pro Forma MISC INSURANCE EXP Adjustment — **$ 3,240**
(Line 5 - Line 3)

DIRECTORS & OFFICERS (D&O) / Fiduciary

E. 1. CITIZENS - D&O/Fiduciary Insurance Exp/Premium - Actual @12/31/01 — $ 596,680

2. NAGD - D&O/Fiduciary Insurance Premium Factor - Actual @12/31/01 — 1.86%
(NAGD # of Employees Budget '2001 /Total CITIZENS Employees Budget '2001)

3. NAGD - D&O/Fiduciary Insurance Exp - Actual @12/31/01 — $ 11,098
(Line 1* Line 2)

4. NAGD - D&O/Fiduciary Insurance Exp Y-T-D Actual @04/30/02 — $ 6,164

5. NAGD - Pro Forma Annualized D&O/Fiduciary Insurance Expense — $ 18,491
(Line 4 * 3)

6. NAGD - Pro Forma D&O/Fiduciary INSURANCE EXP Adjustment — **$ 7,393**
(Line 5 - Line 3)

F. 1. SCGD Natural Account to FERC Adjustment for INSURANCE Exp @ 12/31/01 — 154

2. SCGD Natural Account to FERC Pro Forma Adjustment for INSURANCE Exp — 10

G.	1.	**Total NAGD - INSURANCE EXPENSE @ 12/31/01** (Line A4 + Line B3 + Line C3 + Line D3 + Line E3 + Line F1)	**$**	**97,435**
	2.	**Total NAGD - Pro Forma INSURANCE EXPENSE Adjustment** (Line A7 + Line B6 + Line C6 + Line D6 + Line E6 + F2)	**$**	**11,086**
	3.	**Total NAGD - Pro Forma INSURANCE EXPENSE** (Line G1 + Line G2)	**$**	**108,521**

SANTA CRUZ GAS DIVISION
Insurance Expense
For the Pro Forma TEST YEAR @ December 31, 2001

Line #		
	ALL RISK INSURANCE	
A.	1. ACTUAL Consolidated CITIZENS Gross Plant @ 12/31/01	$ 8,687,201,266
	2. All Risk / Property Insurance Allocable Premium - Actual @ 12/31/01	$ 3,134,389
	3. SCGD ALL RISK Premium Factor - Actual @12/31/01 (SCGD - Ins Prop Values '01 /Total '01 CITIZENS Ins Prop Values)	0.150%
	4. SCGD - All Risk Insurance Expense - Actual @12/31/01 (Line 2 * Line 3)	$ 4,702
	5. SCGD - All Risk Insurance Expense Y-T-D Actual @04/30/02	$ 1,519
	6. SCGD - Pro Forma Annualized All Risk Insurance Expense (Line 5 * 3)	$ 4,557
	7. SCGD - Pro Forma ALL RISK INSURANCE EXP Adjustment (Line 6 - Line 4)	**$ (145)**
	COMPREHENSIVE CRIME	
B.	1. Consolidated CITIZENS - Comp CRIME Insurance Exp/Premium - Actual @12/31/01	$ 31,600
	2. SCGD - Comp CRIME Premium Factor - Actual @12/31/01 (SCGD # of Employees @ 12/31/01 /Total CITIZENS Employee@12/31/01)	0.070%
	3. SCGD - Comp CRIME Insurance Exp - Actual @12/31/01 (Line 1* Line 2)	$ 22
	4. SCGD - Comp CRIME Insurance Exp Y-T-D Actual @04/30/02	$ 18
	5. SCGD - Pro Forma Annualized Comp CRIME Insurance Expense (Line 4 * 3)	$ 54
	6. SCGD - Pro Forma COMPREHENSIVE CRIME INSURANCE EXP Adjustment (Line 5 - Line 3)	**$ 32**
	TRAVEL ACCIDENT INSURANCE	
C.	1. Consolidated CITIZENS - TRAVEL Insurance Exp/Premium - Actual @12/31/01	$ 21,423
	2. SCGD - TRAVEL Premium Factor - Actual @12/31/01 (SCGD # of Employees @ 12/31/01 /Total CITIZENS Employee@12/31/01)	0.07%
	3. SCGD - TRAVEL Insurance Exp - Actual @12/31/01 (Line 1* Line 2)	$ 15
	4. SCGD - TRAVEL Insurance Exp Y-T-D Actual @04/30/02	$ 6
	5. SCGD - Pro Forma Annualized TRAVEL Insurance Expense (Line 5 * 3)	$ 18
	6. SCGD - Pro Forma TRAVELINSURANCE EXP Adjustment (Line 5 - Line 3)	**$ 3**

SANTA CRUZ GAS DIVISION
Insurance Expense
For the Pro Forma TEST YEAR @ December 31, 2001

Line #

MISCELLANEOUS COVERAGES*

D.	1. CITIZENS - MISC Insurance Premium on Common Coverage - Actual @12/31/01		$82,290
	2. SCGD - MISC Insurance Premium Factor on Common Coverage- BDGTED '2001 (SCGD Participation Factor Budget '2001 /Total CITIZENS MISC Distribution Budget '2001)		0.21%
	3. SCGD - MISC Insurance Exp on Common Coverage - Actual @12/31/01 (Line 1* Line 2)	$	177

* MISCELLANEOUS Coverage includes: Other Misc & Special Coverage

	Total Misc		Special		Other Misc		Surety
$	82,290	$	2,760	$	11,010	$	68,520
	SCGD%:						
	0.215%		0.070%		0.070%		0.244%
	SCGD Charge:						
$	177	$	2	$	8	$	167

	4. SCGD - MISC Insurance Exp Y-T-D Actual @04/30/02	$	101
	5. SCGD - Pro Forma Annualized Misc Insurance Expense (Line 4 * 3)	$	303
	6. SCGD - Pro Forma MISC INSURANCE EXP Adjustment (Line 5 - Line 3)	**$**	**126**

DIRECTORS & OFFICERS (D&O) / Fiduciary

E.	1. CITIZENS - D&O/Fiduciary Insurance Exp/Premium - Actual @12/31/01	$	596,680
	2. SCGD - D&O/Fiduciary Insurance Premium Factor - Actual @12/31/01 (SCGD # of Employees Budget '2001 /Total CITIZENS Employees Budget '2001)		0.07%
	3. SCGD - D&O/Fiduciary Insurance Exp - Actual @12/31/01 (Line 1* Line 2)	$	418
	4. SCGD - D&O/Fiduciary Insurance Exp Y-T-D Actual @04/30/02	$	194
	5. SCGD - Pro Forma Annualized D&O/Fiduciary Insurance Expense (Line 4 * 3)	$	582
	6. SCGD - Pro Forma D&O/Fiduciary INSURANCE EXP Adjustment (Line 5 - Line 3)	**$**	**164**

F.	1. SCGD Natural Account to FERC Adjustment for INSURANCE Exp @ 12/31/01		12
	2. SCGD Natural Account to FERC Pro Forma Adjustment for INSURANCE Exp		1

G.	1.	**Total SCGD - INSURANCE EXPENSE @ 12/31/01** (Line A4 + Line B3 + Line C3 + Line D3 + Line E3 + Line F1)	**$**	**5,346**
	2.	**Total SCGD - Pro Forma INSURANCE EXPENSE Adjustment** (Line A7 + Line B6 + Line C6 + Line D6 + Line E6 + F2)	**$**	**169**
	3.	**Total SCGD - Pro Forma INSURANCE EXPENSE** (Line G1 + Line G2)	**$**	**5,515**

3

ARIZONA GAS DIVISION
Injuries and Damages Expense
For the Pro Forma TEST YEAR @ December 31, 2001

Line #			
		GENERAL LIABILITY	
A.	1.	CITIZENS General Liability Premium (all operations) - ACTUAL 12/31/01	$ 3,289,944
	2.	AGD PL&PD General Liability Factor - ACTUAL 12/31/01 (('2001 PLAN AGD # of Customers / '2001 PLAN Total CUC # of Customers) * connection rate of .74220)	2.530%
	3.	AGD - General Liability Premium Charges Distribution - ACTUAL 12/31/01 (Line 1 * Line 2)	$ 83,236
	4.	AGD - General Liability Premium Charges Distribution - ACTUAL through 04/30/02	$ 25,519
	5.	AGD - General Liability Premium Charges Distribution - Annualized through 12/31/02 (Line 4 * 3)	$ 76,556
	6.	AGD - General Liability Premium Charges Distribution - Pro Forma Test Year Adjustment (Line 5 - Line 3)	**$ (6,680)**
		EXCESS LIABILITY	
B.	1.	CITIZENS Excess Liability 1st LAYER Premium (all operations) - ACTUAL 12/31/01	$ 1,624,518
	2.	AGD Excess Liability 1st LAYER Premium Factor - ACTUAL 12/31/01 (ACTUAL 12/31/01 4-FACTOR Restated for Excess Liability Pool (all operations))	2.340%
	3.	AGD Excess Liability 1st LAYER Premium Distribution - ACTUAL 12/31/01 (Line 1 * Line 2)	$ 38,014
	4.	AGD Excess Liability 1st LAYER Premium Distribution - ACTUAL through 04/30/02	$ 23,899
	5.	AGD Excess Liability 1st LAYER Premium Distribution - Annualized for 12/31/02 (Line 4 * 3)	$ 71,696
	6.	AGD Excess Liability 1st LAYER Premium Distribution - Pro Forma Test Year Adjustment (Line 5 - Line 3)	**$ 33,682**
	7.	CITIZENS Excess Liability 2nd LAYER Premium for All Operations - ACTUAL 12/31/01	$ 144,700
	8.	AGD Excess Liability 2nd LAYER Premium Factor - ACTUAL 12/31/01 (ACTUAL 12/31/01 4-FACTOR Restated for Excess Liability Pool for All Operations)	1.910%
	9.	AGD Excess Liability 2nd LAYER (All Ops) Premium Distribution - ACTUAL 12/31/01 (Line 6 * Line 7)	$ 2,764
	10.	AGD Excess Liability 2nd LAYER (All Ops) Premium Distribution - ACTUAL through 04/30/02	$ -
	11.	AGD Excess Liability 2nd LAYER (All Ops) Premium Distribution - Annualized for 12/31/02 (Line 10 * 3)	$ -
	12.	AGD Excess Liability 2nd LAYER (All Ops) Premium Distribution - Pro Forma Test Year Adjustment (Line 11 - Line 9)	**$ (2,764)**

ARIZONA GAS DIVISION
Injuries and Damages Expense
For the Pro Forma TEST YEAR @ December 31, 2001

Line #		
13.	CITIZENS Excess Liability 2nd LAYER Premium for Gas Operations only - ACTUAL 12/31/01	$ 133,650
14.	AGD Excess Liability 2nd LAYER Premium Factor - ACTUAL 12/31/01 (ACTUAL 12/31/01 4-FACTOR Restated for Excess Liability Pool for Gas Operations only)	41.325%
15.	AGD Excess Liability 2nd LAYER (Gas Ops Only) Premium Distribution - ACTUAL 12/31/01 (Line 6 * Line 7)	$ 55,231
16.	AGD Excess Liability 2nd LAYER (Gas Ops Only) Premium Distribution - ACTUAL through 04/30/02	$ 20,894
17.	AGD Excess Liability 2nd LAYER (Gas Ops Only) Premium Distribution - Annualized for 12/31/02 (Line 10 * 3)	$ 62,681
18.	AGD Excess Liability 2nd LAYER (Gas Ops Only) Premium Distribution - Pro Forma Test Year Adj	**$ 7,450**
19.	AGD TOTAL Excess Liability (1st & 2nd Combined) Premium - PRO FORMA Test Year Adjustment (Line 6 + Line 12 + Line 18)	**$ 41,132**

WORKER'S COMPENSATION

C. 1.	CUC Actual 12/31/2001 Workers Compensation Premium	$ 2,489,984
2.	AGD Workers Compensation Cost ACTUAL @ Dec. 31, 2001	

(Citizens Premium/Salary Basis as a % Mix Clerical / Field * Rate(Clerical / Field) * Experience Modifier * % of Total Worker's Comp Premium Pool)

Labor Category	Premium Basis	Class Rate	Exp Modifier	Earned Premium	
Clerical	$2.804M	0.27	0.87	$ 7,458	
Sales	0	0	0	$ -	
Gas	$4.323M	2.43	0.87	$ 110,750	$ 61,629
				$ 118,208	

Earned Premium	Weighted	
$ 118,208	0.52	$ 61,629

3.	AGD Workers Compensation Cost ACTUAL through 04/30/02	$ 27,112
4.	AGD Workers Compensation Cost Annualized for 12/31/02 (Line 3 * 3)	$ 81,335
5.	AGD Workers Compensation Cost PRO FORMA Test Year Adjustment (Line 4 - Line 2)	**$ 19,706**
D. 1.	AGD Natural Account to FERC reclass Adjustment for INJURIES & DAMAGES Exp @ 12/31/01	$ (12,468)
2.	AGD Natural Account to FERC reclass Pro Forma Adjustment for INJURIES & DAMAGES Exp	$ -
E. 1.	**Total AGD - INJURIES & DAMAGES EXPENSE @ 12/31/01** (Line A3 + Line B3 + Line B9 + B15 + Line C2 + Line D1)	$ 228,406
2.	**Toatl AGD - Pro Forma INJURIES & DAMAGES EXPENSE Adjustment** (Line A6 + Line B19 + Line C5+ Line D2)	$ 54,158
3.	**Total AGD - Pro Forma INJURIES & DAMAGES EXPENSE** (Line E1 + Line E2)	**$ 282,564**

NORTHERN ARIZONA GAS DIVISION
Injuries and Damages Expense
For the Pro Forma TEST YEAR @ December 31, 2001

Line #			
	GENERAL LIABILITY		
A. 1.	CITIZENS General Liability Premium (all operations) - ACTUAL 12/31/01	$	3,289,944
2.	NAGD PL&PD General Liability Factor - ACTUAL 12/31/01 (('2001 PLAN NAGD # of Customers / '2001 PLAN Total CUC # of Customers) * connection rate of .74220)		2.380%
3.	NAGD - General Liability Premium Charges Distribution - ACTUAL 12/31/01 (Line 1 * Line 2)	$	78,301
4.	NAGD - General Liability Premium Charges Distribution - ACTUAL through 04/30/02	$	23,983
5.	NAGD - General Liability Premium Charges Distribution - Annualized through 12/31/02 (Line 4 * 3)	$	71,948
6.	NAGD - General Liability Premium Charges Distribution - Pro Forma Test Year Adjustment (Line 5 - Line 3)	**$**	**(6,353)**
	EXCESS LIABILITY		
B. 1.	CITIZENS Excess Liability 1st LAYER Premium (all operations) - ACTUAL 12/31/01		1,624,518
2.	NAGD Excess Liability 1st LAYER Premium Factor - ACTUAL 12/31/01 (ACTUAL 12/31/01 4-FACTOR Restated for Excess Liability Pool (all operations))		2.195%
3.	NAGD Excess Liability 1st LAYER Premium Distribution - ACTUAL 12/31/01 (Line 1 * Line 2)	$	35,658
4.	NAGD Excess Liability 1st LAYER Premium Distribution - ACTUAL through 04/30/02	$	22,563
5.	NAGD Excess Liability 1st LAYER Premium Distribution - Annualized for 12/31/02 (Line 4 * 3)	$	67,688
6.	NAGD Excess Liability 1st LAYER Premium Distribution - Pro Forma Adjustment (Line 5 - Line 3)	**$**	**32,030**
7.	CITIZENS Excess Liability 2nd LAYER Premium for All Operations - ACTUAL 12/31/01	$	144,700
8.	NAGD Excess Liability 2nd LAYER Premium Factor - ACTUAL 12/31/01 (ACTUAL 12/31/01 4-FACTOR Restated for Excess Liability Pool for All Operations)		1.790%
9.	NAGD Excess Liability 2nd LAYER (All Ops) Premium Distribution - ACTUAL 12/31/01 (Line 6 * Line 7)	$	2,590
10.	NAGD Excess Liability 2nd LAYER (All Ops) Premium Distribution - ACTUAL through 04/30/02	$	-
11.	NAGD Excess Liability 2nd LAYER (All Ops) Premium Distribution - Annualized for 12/31/02 (Line 10 * 3)	$	-
12.	NAGD Excess Liability 2nd LAYER (All Ops) Premium Distribution - Pro Forma Adjustment (Line 11 - Line 9)	$	(2,590)

NORTHERN ARIZONA GAS DIVISION
Injuries and Damages Expense
For the Pro Forma TEST YEAR @ December 31, 2001

Line #

13. CITIZENS Excess Liability 2nd LAYER Premium for Gas Operations only - ACTUAL 12/31/01 — $ 133,650

14. NAGD Excess Liability 2nd LAYER Premium Factor - ACTUAL 12/31/01 — 38.760%
(ACTUAL 12/31/01 4-FACTOR Restated for Excess Liability Pool for Gas Operations only)

15. NAGD Excess Liability 2nd LAYER (Gas Ops Only) Premium Distribution - ACTUAL 12/31/01 — $ 51,803
(Line 6 * Line 7)

16. NAGD Excess Liability 2nd LAYER (Gas Ops Only) Premium Distribution - ACTUAL through 04/30/02 — $ 19,581

17. NAGD Excess Liability 2nd LAYER (Gas Ops Only) Premium Distribution - Annualized for 12/31/02 — $ 58,744
(Line 10 * 3)

18. NAGD Excess Liability 2nd LAYER (Gas Ops Only) Premium Distribution - Pro Forma Adjustment — $ 6,941

19. NAGD TOTAL Excess Liability (1st & 2nd Combined) Premium - PRO FORMA Adjustment — **$ 38,971**
(Line 6 + Line 12 + Line 18)

WORKER'S COMPENSATION

C. 1. CUC Actual 12/31/2001 Workers Compensation Premium — $ 2,489,984

2. NAGD Workers Compensation Cost ACTUAL 12/31/01 / PRO FORMA @ Dec. 31, 2001 — $ 61,402
(Citizens Premium/Salary Basis as a % Mix Clerical / Field * Rate(Clerical / Field) * Experience Modifier * % of Total Worker's Comp Premium Pool)

Labor Category	Premium Basis	Class Rate	Exp Modifier	Earned Premium
Clerical	$2.488M	0.27	0.87	$ 6,948
Sales	0	0	0	$ -
Gas	$4.322M	2.43	0.87	$ 110,750
				$ 117,698

Earned Premium	Weighted	
$ 117,698	0.52	$ 61,402

3. NAGD Workers Compensation Cost ACTUAL through 04/30/02 — $ 26,962

4. NAGD Workers Compensation Cost Annualized for 12/31/02 — $ 80,886
(Line 3 * 3)

5. NAGD Workers Compensation Cost PRO FORMA Adjustment — **$ 19,484**

D. 1. NAGD Natural Account to FERC reclass Adjustment for INJURIES & DAMAGES Exp @ 12/31/01 — $ (12,791)

2. NAGD Natural Account to FERC reclass Pro Forma Adjustment for INJURIES & DAMAGES Exp — $ (1)

E. 1. **Total NAGD - INJURIES & DAMAGES EXPENSE @ 12/31/01** — $ 216,963
(Line A3 + Line B3 + Line B9 + B15 + Line C2 + Line D1)

2. **Total NAGD - Pro Forma INJURIES & DAMAGES EXPENSE Adjustment** — $ 52,101
(Line A6 + Line B19 + Line C5+ Line D2)

3. **Total NAGD - Pro Forma INJURIES & DAMAGES EXPENSE** — **$ 269,064**
(Line E1 + Line E2)

SANTA CRUZ GAS DIVISION
Injuries and Damages Expense
For the Pro Forma TEST YEAR @ December 31, 2001

Line #			
	GENERAL LIABILITY		
A. 1.	CITIZENS General Liability Premium (all operations) - ACTUAL 12/31/01	$	3,289,944
2.	SCGD PL&PD General Liability Factor - ACTUAL 12/31/01 (('2001 PLAN SCGD # of Customers / '2001 PLAN Total CUC # of Customers) * connection rate of .74220)		0.150%
3.	SCGD - General Liability Premium Charges Distribution - ACTUAL 12/31/01 (Line 1 * Line 2)	$	4,935
4.	SCGD - General Liability Premium Charges Distribution - ACTUAL through 04/30/02	$	1,536
5.	SCGD - General Liability Premium Charges Distribution - Annualized through 12/31/02 (Line 4 * 3)	$	4,608
6.	SCGD - General Liability Premium Charges Distribution - Pro Forma Test Year Adjustment (Line 5 - Line 3)	**$**	**(327)**
	EXCESS LIABILITY		
B. 1.	CITIZENS Excess Liability 1st LAYER Premium (all operations) - ACTUAL 12/31/01	$	1,624,518
2.	SCGD Excess Liability 1st LAYER Premium Factor - ACTUAL 12/31/01 (ACTUAL 12/31/01 4-FACTOR Restated for Excess Liability Pool (all operations))		0.145%
3.	SCGD Excess Liability 1st LAYER Premium Distribution - ACTUAL 12/31/01 (Line 1 * Line 2)	$	2,356
4.	SCGD Excess Liability 1st LAYER Premium Distribution - ACTUAL through 04/30/02	$	1,336
5.	SCGD Excess Liability 1st LAYER Premium Distribution - Annualized for 12/31/02 (Line 4 * 3)	$	4,008
6.	SCGD Excess Liability 1st LAYER Premium Distribution - Pro Forma Test Year Adjustment (Line 5 - Line 3)	**$**	**1,652**
7.	CITIZENS Excess Liability 2nd LAYER Premium for All Operations - ACTUAL 12/31/01	$	144,700
8.	SCGD Excess Liability 2nd LAYER Premium Factor - ACTUAL 12/31/01 (ACTUAL 12/31/01 4-FACTOR Restated for Excess Liability Pool for All Operations)		0.120%
9.	SCGD Excess Liability 2nd LAYER (All Ops) Premium Distribution - ACTUAL 12/31/01 (Line 6 * Line 7)	$	174
10.	SCGD Excess Liability 2nd LAYER (All Ops) Premium Distribution - ACTUAL through 04/30/02	$	-
11.	SCGD Excess Liability 2nd LAYER (All Ops) Premium Distribution - Annualized for 12/31/02 (Line 10 * 3)	$	-
12.	SCGD Excess Liability 2nd LAYER (All Ops) Premium Distribution - Pro Forma Test Year Adjustment (Line 11 - Line 9)	$	(174)

SANTA CRUZ GAS DIVISION
Injuries and Damages Expense
For the Pro Forma TEST YEAR @ December 31, 2001

Line #			
13.	CITIZENS Excess Liability 2nd LAYER Premium for Gas Operations only - ACTUAL 12/31/01	$	133,650
14.	SCGD Excess Liability 2nd LAYER Premium Factor - ACTUAL 12/31/01 (ACTUAL 12/31/01 4-FACTOR Restated for Excess Liability Pool for Gas Operations only)		2.565%
15.	SCGD Excess Liability 2nd LAYER (Gas Ops Only) Premium Distribution - ACTUAL 12/31/01 (Line 6 * Line 7)	$	3,428
16.	SCGD Excess Liability 2nd LAYER (Gas Ops Only) Premium Distribution - ACTUAL through 04/30/02	$	1,312
17.	SCGD Excess Liability 2nd LAYER (Gas Ops Only) Premium Distribution - Annualized for 12/31/02 (Line 10 * 3)	$	3,937
18.	SCGD Excess Liability 2nd LAYER (Gas Ops Only) Premium Distribution - Pro Forma Test Year Adj	$	509
19.	SCGD TOTAL Excess Liability (1st & 2nd Combined) Premium - PRO FORMA Test Year Adj (Line 6 + Line 12 + Line 18)	**$**	**2,161**

WORKER'S COMPENSATION

C. 1. CUC Actual 12/31/2001 Workers Compensation Premium — $ 2,489,984

2. SCGD Workers Compensation Cost ACTUAL 12/31/01 / PRO FORMA @ Dec. 31, 2001 — $ 227

(Citizens Premium/Salary Basis as a % Mix Clerical / Field * Rate(Clerical / Field) * Experience Modifier * % of Total Worker's Comp Premium Pool)

Labor Category	Premium Basis	Class Rate	Exp Modifier	Earned Premium
Clerical	$.316M	0.27	0.87	$ 510
Sales	0	0	0	$ -
Gas	0	2.43	0.87	$ -
				$ 510

Earned Premium	Weighted	
$ 510	0.45	$ 227

3.	SCGD Workers Compensation Cost ACTUAL through 04/30/02	$	150
4.	SCGD Workers Compensation Cost Annualized for 12/31/02 (Line 3 * 3)	$	449
5.	SCGD Workers Compensation Cost PRO FORMA Test Year Adjustment	**$**	**222**

D. 1.	SCGD Natural Account to FERC reclass Adjustment for INJURIES & DAMAGES Exp @ 12/31/01	$	323
2.	SCGD Natural Account to FERC reclass Pro Forma Adjustment for INJURIES & DAMAGES Exp	$	1

E. 1.	**Total SCGD - INJURIES & DAMAGES EXPENSE @ 12/31/01** (Line A3 + Line B3 + Line B9 + B15 + Line C2 + Line D1)	$	11,443
2.	**Total SCGD - Pro Forma INJURIES & DAMAGES EXPENSE Adjustment** (Line A6 + Line B19 + Line C5+ Line D2)	$	2,057
3.	**Total SCGD - Pro Forma INJURIES & DAMAGES EXPENSE** (Line E1 + Line E2)	**$**	**13,500**

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EXHIBIT-RJM-04
Citizens Communications Co. - AGD
Docket No. G-01032A-02-
Summary Emp Welfare & Pension

Employee Welfare Benefits & Pension Expense
AGD Employees PRO FORMA Test Year Calculation
@ December 31, 2001

		Test Year ACTUALS	Pro Forma Adjustments	Pro Forma EXPENSE
	Emp Benefits (Union & Non-Union):			
1.	Medical & Dental	$ 982,909	$ (64,349)	$ 918,560
2.	Vision	$ 20,855	$ (1,055)	$ 19,800
3.	EAP /Flex Admin	$ 6,392	$ 474	$ 6,866
4.	Long Term Disability	$ 11,754	$ 24,638	$ 36,392
5.	Life	$ 34,552	$ (16,186)	$ 18,366
6.	CIP / IDCIP	$ 122,841	$ 239,576	$ 362,417
7.	401-K	$ 179,561	$ (36,875)	$ 142,686
8.	Pension	$ 339,406	$ 214,507	$ 553,913
9.	Post Retirement Ben	$ 33,281	$ 9,022	$ 42,303
10.	RECLASS FERC / Natural	$ 8,453	$ -	$ 8,453
11.	TOTAL	$ 1,740,003	$ 369,753	$2,109,756

EXHIBIT-RJM-04
Citizens Communications Co. - AGD
Docket No. G-01032A-02-
Summary Emp Welfare & Pension

Employee Welfare Benefits & Pension Expense
AGD Utility Employees PRO FORMA Test Year Calculation
@ December 31, 2001

		Test Year ACTUALS	Pro Forma Adjustments	Pro Forma EXPENSE
	Emp Benefits (Union & Non-Union):			
1.	Medical & Dental	$ 956,279	$ (67,723)	$ 888,556
2.	Vision	$ 20,081	$ (2,978)	$ 17,103
3.	EAP /Flex Admin	$ 6,148	$ 494	$ 6,642
4.	Long Term Disability	$ 11,443	$ 23,760	$ 35,203
5.	Life	$ 33,350	$ (15,583)	$ 17,767
6.	CIP / IDCIP	$ 118,632	$ 240,327	$ 358,959
7.	401-K	$ 160,018	$ (21,474)	$ 138,544
8.	Pension	$ 333,209	$ 196,791	$ 530,000
9.	Post Retirement Ben	$ 24,494	$ 2,705	$ 27,199
10.	RECLASS FERC / Natural	$ 8,453		$ 8,453
11.	TOTAL	$ 1,672,106	$ 356,320	$2,028,426

EXHIBIT-RJM-04
Citizens Communications Co. - AGD
Docket No. G-01032A-02-
Summary Emp Welfare & Pension

Employee Welfare Benefits & Pension Expense
SCGD Utility Employees PRO FORMA Test Year Calculation
@ December 31, 2001

		Test Year ACTUALS	Pro Forma Adjustments	Pro Forma EXPENSE
	Emp Benefits (Union & Non-Union):			
1.	Medical & Dental	$ 26,630	$ 3,374	$ 30,004
2.	Vision	$ 774	$ 1,923	$ 2,697
3.	EAP /Flex Admin	$ 244	$ (20)	$ 224
4.	Long Term Disability	$ 311	$ 878	$ 1,189
5.	Life	$ 1,203	$ (604)	$ 599
6.	CIP / IDCIP	$ 4,209	$ (751)	$ 3,458
7.	401-K	$ 19,543	$ (15,401)	$ 4,142
8.	Pension	$ 6,197	$ 17,716	$ 23,913
9.	Post Retirement Ben	$ 8,787	$ 6,317	$ 15,104
10.	RECLASS FERC / Natural			
11.	TOTAL	$ 67,897	$ 13,433	$ 81,330

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TOTAL ADMINISTRATIVE OFFICE Pro Forma Expense & Adjustments

Arizona Gas Division

Total Admin Expenses @ 12/31/01	$ 47,795,733	
Total Admin Expenses Charged to NAGD @ 12/31/01	$ 1,726,142	
Adjustments:		
Previously Disallowed and/or Contentious Items	$ (160,743)	
Removal of Depreciation Expense /Carrying Cost	$ (374,039)	
Pro Forma GRIFFITH & Paulden Line Adj	$ (19,645)	
Pro Forma 04/30/02 Actuals Adjustment	$ (24,245)	
ORCOM Implementation & Operation Adj	$ (26,900)	
ADP Services Adj	$ 42,230	
SAP Ongoing Operations & Maintenance Adj	$ 37,200	
Total Pro Forma Adjustment	$ (526,142)	
Total Pro Forma Admin Expense		$ 1,200,000

Exhibit-RJM-05
Citizens Communications - AGD
Docket No. G-1032A-02-
Administrative Expense

STAMFORD ADMINISTRATIVE OFFICE Pro Forma Expense & Adjustments

Arizona Gas Division

Total SAO Expenses @ 12/31/01	$ 34,080,178	
SAO Expenses Charged to NAGD @ 12/31/01	$ 1,148,857	
Adjustments:		
Previously Disallowed and/or Contentious Items	$ (135,818)	
Removal of Depreciation Expense	$ (346,422)	
Pro Forma GRIFFITH & Paulden Line Adj	$ (13,200)	
Pro Forma 04/30/02 Actuals Adjustment	$ (218,054)	
Total Pro Forma Adjustment	$ (713,494)	
Total Pro Forma SAO Expense		$ 435,363

Exhibit-RJM-05
Citizens Communications - AGD
Docket No. G-1032A-02-
Administrative Expense

PUBLIC SERVICE OFFICE Pro Forma Expense & Adjustments

Arizona Gas Division

Total PSO Expenses @ 12/31/01	$	7,823,355		
PSO Expenses Charged to NAGD @ 12/31/01	$	419,278		
Adjustments:				
Removal of Depreciation Expense	$	(23,508)		
ORCOM Implementation & Operation Adj	$	(26,900)		
CIP Adjustment	$	(22,367)		
ADP Services Adj	$	42,230		
SAP Ongoing Operations & Maintenance Adj	$	37,200		
Pro Forma GRIFFITH & Paulden Line Adj	$	(4,641)		
Pro Forma 04/30/02 Actuals Adjustment	$	275,772		
Total Pro Forma Adjustment	$	277,786		
Total Pro Forma PSO Expense			$	697,064
RECLASS between FERC & Natural Account			$	8,150
Total Adjusted Pro Forma PSO Expense			$	705,214

Exhibit-RJM-05
Citizens Communications - AGD
Docket No. G-1032A-02-
Administrative Expense

LOCAL AREA / WIDE AREA / E-MAIL NETWORKS Pro Forma Exp & Adjstmnts

Total LAN WAN EMAIL Srvc Expenses @ 12/31/01	$ 5,892,200		
.AN WAN EMAIL Srvc Expenses Charged to NAGD @ 12/31/01	$ 158,007		
Removal of Depreciation Expense	$ (4,109)		
CIP Adjustment	$ (2,558)		
Removal of Carrying Cost	$ -		
Pro Forma GRIFFITH & Paulden Line Adj	$ (1,804)		
Pro Forma 04/30/02 Actuals Adjustment	$ (90,113)		
Total Pro Forma Adjustment	$ (98,584)		
Total Pro Forma SAO Expense			$ 59,423

TOTAL ADMINISTRATIVE OFFICE Pro Forma Expense & Adjustments

Northern Arizona Gas Division

Total Admin Expenses @ 12/31/01	$ 47,795,733	
Total Admin Expenses Charged to NAGD @ 12/31/01	$ 1,604,889	
Adjustments:		
Previously Disallowed and/or Contentious Items	$ (150,882)	
Removal of Depreciation Expense /Carrying Cost	$ (348,005)	
Pro Forma GRIFFITH & Paulden Line Adj	$ (19,645)	
Pro Forma 04/30/02 Actuals Adjustment	$ (13,352)	
ORCOM Implementation & Operation Adj	$ (25,000)	
ADP Services Adj	$ 39,730	
SAP Ongoing Operations & Maintenance Adj	$ 35,000	
Total Pro Forma Adjustment	$ (482,154)	
Total Pro Forma Admin Expense		$ 1,122,735

Santa Cruz Gas Division

Total Admin Expenses @ 12/31/01	$ 47,795,733
Total Admin Expenses Charged to SCGD @ 12/31/01	$ 121,253
Adjustments:	
Previously Disallowed and/or Contentious Items	$ (9,861)
Removal of Depreciation Expense	$ (26,034)
Pro Forma 04/30/02 Actuals Adjustment	$ (10,893)
ORCOM Implementation & Operation Adj	$ (1,900)
ADP Services Adj	$ 2,500

SAP Ongoing Operations & Maintenance Adj	$	2,200	
Total Pro Forma Adjustment	$	(34,127)	
Total Pro Forma Admin Expense			$ 87,126

STAMFORD ADMINISTRATIVE OFFICE Pro Forma Expense & Adjustments

Northern Arizona Gas Division

Total SAO Expenses @ 12/31/01	$ 34,080,178			
SAO Expenses Charged to NAGD @ 12/31/01	$ 1,078,430			
Adjustments:				
Previously Disallowed and/or Contentious Items	$ (127,492)			
Removal of Depreciation Expense	$ (325,187)		0.0242	Adj Closing 4-Fctr
			0.0245	Closing 4-Fctr
Pro Forma GRIFFITH & Paulden Line Adj	(13,200)			
			0.9877551	% Change
Pro Forma 04/30/02 Actuals Adjustment	$ (205,491)			
			-0.0122449	Adjustment Factor
Total Pro Forma Adjustment	$ (671,370)			
Total Pro Forma SAO Expense		$ 407,060		

Santa Cruz Gas Division

Total SAO Expenses @ 12/31/01	$ 34,080,178	
SAO Expenses Charged to SCGD @ 12/31/01	$ 70,427	
Adjustments:		
Previously Disallowed and/or Contentious Items	$ (8,326)	
Removal of Depreciation Expense	$ (21,235)	
Pro Forma 04/30/02 Actuals Adjustment	$ (12,563)	$ (9,162)
Total Pro Forma Adjustment	$ (42,124)	
Total Pro Forma SAO Expense		$ 28,303

PUBLIC SERVICE OFFICE Pro Forma Expense & Adjustments

Northern Arizona Gas Division

Total PSO Expenses @ 12/31/01	$ 7,823,355				
PSO Expenses Charged to NAGD @ 12/31/01	$ 379,154				
Adjustments:					
Removal of Depreciation Expense	$ (18,990)				
ORCOM Implementation & Operation Adj	$ (25,000)				
CIP Adjustment	$ (20,989)				
ADP Services Adj	$ 39,730				
				0.0242	Adj Closing 4-Fctr
SAP Ongoing Operations & Maintenance Adj	$ 35,000			0.0245	Closing 4-Fctr
Pro Forma GRIFFITH & Paulden Line Adj	(4,641)			0.987755	% Change
Pro Forma 04/30/02 Actuals Adjustment	$ 275,772			-0.012245	Adjustment Factor
Total Pro Forma Adjustment	$ 280,882				
Total Pro Forma PSO Expense		$ 660,036			

Santa Cruz Gas Division

Total PSO Expenses @ 12/31/01	$ 7,823,355	
PSO Expenses Charged to SCGD @ 12/31/01	$ 40,124	
Adjustments:		
Removal of Depreciation Expense	$ (4,518)	
ORCOM Implementation & Operation Adj	$ (1,900)	
CIP Adjustment	$ (1,378)	
ADP Services Adj	$ 2,500	
SAP Ongoing Operations & Maintenance Adj	$ 2,200	
Pro Forma 04/30/02 Actuals Adjustment	$ 8,150	
Total Pro Forma Adjustment	$ 5,054	
Total Pro Forma PSO Expense		$ 45,178

LOCAL AREA / WIDE AREA / E-MAIL NETWORKS Pro Forma Expense & Adjustments

Northern Arizona Gas Division

Total LAN WAN EMAIL Srvc Expenses @ 12/31/01	$	5,892,200				
LAN WAN EMAIL Srvc Expenses Charged to NAGD @ 12/31/01	$	147,305				
Adjustments:						
Removal of Depreciation Expense	$	(3,828)				
CIP Adjustment	$	(2,401)				
Removal of Carrying Cost						
					0.0242	Adj Closing 4-Fctr
Pro Forma GRIFFITH & Paulden Line Adj	$	(1,804)			0.0245	Closing 4-Fctr
Pro Forma 04/30/02 Actuals Adjustment	$	(83,633)			0.987755	% Change
					-0.012245	Adjustment Factor
Total Pro Forma Adjustment	$	(91,666)				
Total Pro Forma LAN WAN Email Srvc Expense			$	55,639		

Santa Cruz Gas Division

Total LAN WAN EMAIL Srvc Expenses @ 12/31/01	$	5,892,200		
LAN WAN EMAIL Srvc Expenses Charged to SCGD @ 12/31/01	$	10,702		
Adjustments:				
Removal of Depreciation Expense	$	(281)		
CIP Adjustment	$	(157)		
Removal of Carrying Charge				
Pro Forma 04/30/02 Actuals Adjustment	$	(6,480)	$	(5,390)
Total Pro Forma Adjustment	$	(6,918)		
Total Pro Forma LAN WAN Email Srvc Expense			$	3,784

EXHIBIT
JA-16
admitted

INTRODUCTION

Q. Please state your name and business address.

A. My name is Anthony Apuzzo. My business address is Citizens Communications Company, Three High Ridge Park, Stamford, Connecticut 06905.

Q. By whom are you employed and in what capacity?

A. I am employed by Citizens Communications Company ("Citizens") as Director, Tax and Actuarial Compliance.

Q. Please summarize your educational background.

A. I graduated from Rochester Institute of Technology in 1984 with a Bachelor of Science Degree in Accounting. I am a CPA, certified in the State of Connecticut.

Q. Please describe your work experience.

A. I joined Citizens in 1987 as a staff Internal Auditor. I was promoted from Senior Auditor into the position of Supervisor, Financial Tax Accounting in 1992. In 1999, I was promoted into my present position. I have been responsible for all of Citizens' income tax accounting activity related to the operating properties including the Northern Arizona Gas Division ("NAGD") and the Santa Cruz Gas Division ("SCGD") since 1992.

Q. What areas will you address in this testimony?

A. I will present the calculation of the accumulated deferred income taxes ("ADIT") included as Schedule B-7 for the Arizona Gas Division ("AGD" or "Company"), which is comprised of the NAGD and SCGD. I will also testify to the AGD's Taxes Other than Income (Adjustment H to Schedule C-2), Prior Period Tax Refunds (Adjustment K to Schedule C-2) and State and Federal Income Taxes (Adjustment S to Schedule C-2).

These schedules were filed as part of this application and are found in their own bound volume.

ADIT

Q. What are deferred income taxes?

A. Deferred income taxes represent the tax effect of differences that arise between the time periods when revenues and expenses are recognized for financial reporting purposes and when they are considered for income tax return purposes. For AGD, the largest such difference is that which exists as a result of the use of accelerated methods and shorter lives in computing tax depreciation, as compared with the manner in which book depreciation is computed. For this purpose, it is useful to distinguish between "timing differences" and "permanent differences."

Q. Please discuss the distinction between "timing differences" and "permanent differences."

A. Timing differences represent disparities between book income before income taxes and taxable income that originate in one or more periods, and reverse or turn around, in one or more subsequent periods. Because public utilities are so capital intensive, the difference between book and tax depreciation is typically the largest timing difference affecting such companies.

Permanent differences represent disparities between book income before income taxes and taxable income, and do not reverse in subsequent periods. Examples of permanent differences include non-taxable interest income from municipal bonds and non-deductible lobbying expenses.

Deferred income taxes are computed for timing differences, but not for permanent differences. The typical accounting for deferred income taxes involves recognition of a deferred income tax expense on the income statement, with a corresponding entry made to a balance sheet ADIT reserve account. As the timing differences reverse over time, the balance of the ADIT reserve account is also reversed.

Q. Please describe Schedule B-7.

A. Schedule B-7 consists of two pages. Page 1 of 2 is a summary page, which groups the various ADIT amounts by Federal and State components. Page 2 of 2 shows the ADIT by component, as recorded and adjusted at December 31, 2001. Columns [1] and [2] show the ADIT resulting from accelerated tax depreciation, Property, Plant & Equipment ("Plant") retirements and capitalized basis differences for Federal and State components, respectively. Columns [3] and [4] show the advanced income taxes ("AIT") resulting from the requirement to capitalize interest for income tax purposes ("CAP Interest"). Columns [5] and [6] reflect the AIT required on Contributions-In-Aid-of-Construction ("CIAC"). Columns [7] and [8] reflect the subtotal of columns [1] through [6]. Columns [9] and [10] reflect the AIT required on Advances-In-Aid-of-Construction ("AIAC"). For Columns [1] through [10], the odd-numbered columns provide amounts associated with Federal taxes and the even-numbered columns provide amounts associated with Arizona State taxes. Column [11] shows the ADIT amortized from the Federal Income Tax rate reduction in 1986, the State Income Tax rate reduction in 2001, and the ADIT for Schedule "M" items, which represent tax timing differences other than those related to Plant and AIAC.

Q. Please explain what the ADIT related to the accelerated depreciation represents.

A. This ADIT results from the different rates and methods used in computing depreciation on Plant for income tax purposes as compared with the book rates and method used for computing book depreciation ("Method Difference"). This ADIT also includes the tax effect of the book-tax differences resulting from Plant retirements. These book-tax differences occur because, when Plant is retired, an income tax deduction is allowed for the remaining tax basis of the Plant while, under normal utility accounting, no deduction is recognized for book purposes. Rather, for book accounting, the retirement is reflected as a credit to Plant and a debit to the accumulated depreciation. This has no effect on expenses used to determine the operating income before income taxes for book purposes.

Finally, this ADIT includes the impact of different book and tax amounts of overheads capitalized into the basis of Plant between book and tax. These differences are reflected as adjustments on Citizens' tax returns that result in ADIT at the time Plant is initially capitalized. These temporary book-tax differences will ultimately reverse in the future when depreciation is deducted at different amounts for book and tax reporting over the life of the Plant.

Q. Please explain what the AIT on CAP Interest represents.

A. AIT on CAP Interest represents the amount of taxes paid as a result of the requirement to assign interest to capital expenditures for the purpose of calculating income taxes. This requirement results in the prepayment of taxes that are recovered over the useful tax life of the Plant that was the basis for the initial CAP Interest and related tax payment.

Q. Please describe the AIT on CIAC.

A. These amounts are the taxes paid by Citizens on CIAC amounts received in connection with the construction of plant. Citizens has paid these income tax amounts in the year of receipt and recovers them from the tax depreciation over the life of the CIAC plant. These are amounts of taxes paid in advance of taking the tax depreciation during the life of the Plant related to the CIAC.

Q. Please describe the AIT on AIAC.

A. These amounts are the taxes paid by Citizens on AIAC amounts received in connection with the construction of plant. Citizens receives advances in the form of either plant or cash. Under both forms of advances, Citizens pays income taxes and recovers those tax amounts when it makes refunds to customers pursuant to the advance contracts. Therefore, the book-tax difference is reflected in the liability for customer advances that has been recognized as taxable income when first received.

Q. Please explain the amounts shown for the "RGSM" on Schedule B-7, highlighted in footnote [a].

A. The Reverse South Georgia Method ("RSGM") amounts represent the amount of ADIT that is directly related to (i) the Federal Income Tax ("FIT") rate reduction included among the changes contained in the Tax Reform Act of 1986 ("TRA-86") and (ii) the State Income Tax ("SIT") rate reduction in 2001.

Q. Please describe the FIT rate reduction as it affects ADIT.

A. The reduction of the FIT rate from 46% to 34% meant that Federal income taxes deferred prior to the TRA-86 at the 46% rate would be repaid to the Federal government at the new 34% FIT rate. The difference, if not addressed by regulators, would have been retained by the utility. Regulators have used one of several methods to provide this difference to customers and maintain compliance with the Internal Revenue Code with regard to the Method Difference ADIT amounts. The Arizona Corporation Commission ("Commission") has approved the RSGM to flow this difference back to customers.

Q. Please describe the SIT rate reduction as it affects ADIT.

A. The reduction of the SIT rate from 7.968% to 6.968% in 2001 meant that State income taxes deferred prior to 2001 would be repaid to the State of Arizona at the new 6.968% rate. The difference, if not addressed by regulators, would have been retained by the utility. Consistent with the treatment of the excess Federal ADIT, the AGD is using the RSGM to flow the difference back to customers.

Q. What is the total RGSM for FIT and SIT that is being flowed back to customers?

A. The amortization shown on line 7 of column [11] passes an annual amount to customers so that the difference will be eliminated over the remaining useful life of the Plant that was in place at the time the tax rate changed. The amortization for the test year ended December 31,2001 is $12,791.

Q. Please describe the amount in column [11] shown on line 5, Other Schedule "M" Items.

A. This amount represents the tax-effect of other book-tax timing differences (schedule "M" items) related to amounts that are not already reflected in other columns on schedule B-7. These amounts include Pension Expense, Medical benefits and other amounts that have been included in setting rates for the AGD. Consistent with prior rate applications in Arizona, I have used a four-year average to calculate the amount of the ADIT for these Schedule M items for the 2001 test year, based on the most recent four years of Citizens' income tax filings (1997 through 2000).

Q. What adjustments have been made to the recorded ADIT for 2001?

A. On Schedule B-7, I have included adjustments on:

- Line 2---To reverse 2001 recorded ADIT estimates;
- Line 4---To update the recorded amounts to reflect full normalization as of December 31, 2000;
- Line 5---To reflect the Schedule "M" items for book-tax timing differences that are not included in the ADIT accounts recorded on the AGD's books;
- Line 7---To reflect an updated incremental estimate of ADIT for 2001;

- Line 8---To add ADIT for pro forma plant retirements;
- Line 9---To add ADIT associated with the removal of the Yale Street property from the rate case;
- Line 10---To remove ADIT associated with the recorded NAGD acquisition adjustments;
- Line 11---To remove ADIT related to the Paulden Line Plant that has been removed from rate base in this application;
- Line 12---To remove ADIT relating to an Allowance for Funds Used During Construction ("AFUDC") adjustment;
- Line 13---To remove ADIT related to the Griffith Plant, which has been removed from rate base in this application;
- Line 14---To add ADIT related to the transfer of the Transmission Line from Citizens' Santa Cruz Electric Division to the SCGD; and
- Line 15 –To add ADIT related to the excess ADIT for Income Tax rate changes.

Q. Please describe the adjustment to reverse the 2001 recorded ADIT estimate.

A. The first step in calculating the ADIT adjustments in this case is to remove the amounts that Citizens recorded on its books as the estimated incremental ADIT for 2001. It should be noted that line 1, showing total recorded ADIT as of December 31, 2001, was adjusted in 2001 to reflect Citizens' income tax return filings for tax year 2000. The item labeled "Subtotal" on line 3, therefore, shows the adjusted 2000 ADIT as reflected in the recorded 2001 balances. As discussed below, I adjust this recorded

2000 ADIT level by a number of items, including the most recent estimate of 2001 ADIT (shown on line 7) to derive the appropriate rate year ADIT amount.

Q. Please explain the adjustment to reflect full normalization under Financial Accounting Standards Board ("FASB") 109 on line 4.

A. The adjustment provides the amount needed to reflect in the balance of ADIT the tax effect of all cumulative book-tax differences related to Plant as of December 31, 2000, at current income tax rates.

Q. Why is the calculation based on the book-tax differences as of December 31, 2000, instead of December 31, 2001?

A. This calculation reflects the fact that the 2000 calendar year income tax return is the latest return that Citizens has filed. The 2001 income tax return will not be filed until September (Federal return) and October (State return) of 2002. The estimated deferred income tax for 2001 reflected on line 7 incorporates Citizens' best estimate of a fully normalized incremental ADIT calculation for 2001.

Q. How did you determine the normalization adjustment shown on line 4 of Schedule B-7?

A. The adjustment is based on comparing the recorded ADIT as of December 31, 2000, (adjusted in 2001 to reflect the 2000 tax return filings) with the amount of ADIT computed under a full normalization calculation. This is accomplished by comparing the adjusted remaining tax basis of Plant with the adjusted remaining book basis of Plant. This difference is then tax-effected to arrive at the required level of ADIT under full normalization.

The difference between the required level of ADIT and the adjusted recorded balance of ADIT provides the amount of required adjustment as reflected on line 4.

Q. How do you arrive at the recorded ADIT as of December 31, 2000?

A. As noted above, I derived the recorded ADIT at December 31, 2000, (adjusted for the 2000 tax return filings) by removing the amount recorded on the books during 2001 that relates to the estimated 2001 incremental ADIT. This balance is reflected on line 3, Schedule B-7, in columns [1] through [6].

Q. Which columns of ADIT from Schedule B-7 are included in the recorded ADIT amounts for purposes of this adjustment?

A. Columns [1] through [6], which are summarized in the subtotal columns [7] and [8], are used because only these columns reflect ADIT amounts on book-tax timing differences related to Plant.

Q. Does Schedule B-7 illustrate the ADIT balance under full normalization after this adjustment?

A. Yes. On line 6 in columns [7] and [8] this balance of Federal and State ADIT represents the tax effect of the cumulative net book-tax timing difference related to Plant as of December 31, 2000.

Q. Please explain the estimated deferred income tax for 2001 on line 7.

A. These amounts represent Citizens' best estimate of the 2001 incremental amounts of ADIT for each type of book-tax timing difference as reflected under each column of the Schedule B-7. The amounts also incorporate the

AGD's ratemaking adjustment to recorded book depreciation in arriving at the estimated ADIT for 2001.

Q. Please explain the ADIT adjustments for the pro-forma Plant retirements.

A. This adjustment, as reflected on line 8 of Schedule B-7, is required to reflect the impact on ADIT of the AGD pro-forma Plant retirements that are described in Mr. Doherty's testimony as an adjustment to Schedule B-4A. ADIT is increased when Plant is retired because an income tax deduction is allowed for the remaining tax basis of the Plant that is retired, even though no book deduction is made for the same retirement. The ADIT increase on line 8 is the tax effect of the tax deduction that will be allowed for the remaining tax basis of the Plant that is being retired on a pro-forma basis.

Q. Please explain the ADIT adjustments for the Yale Street property and for other miscellaneous Plant adjustments.

A. These adjustments, on lines 9, 11, 13, and 14, are necessary to adjust the ADIT to reflect the corresponding removal or addition to AGD Plant reflected as part of rate base adjustments presented in Schedule B-4A, and described in Mr. Doherty's testimony.

Q. How were the ADIT adjustments for these Plant adjustments determined?

A. Similar to the full normalization adjustment under FASB 109, the tax effect of the difference between net book basis and net tax basis comprises the ADIT adjustment. The basis was determined as of December 31, 2001, so that no additional adjustments would be required with respect to Citizens' estimated ADIT for 2001 on line 7. That 2001 ADIT estimate on line 7 was made assuming that there were no Plant adjustments.

Q. Please describe your adjustment to ADIT relating to the NAGD acquisition adjustments.

A. As Mr. Doherty states in his testimony, the test year rate base does not include the acquisition adjustments related to: [1] the Southern Union Gas's acquisition of what is now the NAGD; [2] Citizens' acquisition of NAGD from Southern Union Gas, or [3] a certain portion of the costs associated with the Transwestern Pipeline capacity in the early years of the contract with Citizens. I have reduced ADIT by the amounts relating to these items that have been removed from rate base. This adjustment is shown on line 10 of Schedule B-7.

The amount of ADIT removed is computed based on the accumulated depreciation/amortization taken on Citizens' tax returns for the acquisition adjustment from the date of acquisition through the test year (estimated for 2001). The amount of $10,067,009 (representing accumulated depreciation/amortization), tax-effected, yields the ADIT adjustment of $3,979,408, as reflected on line 10 of Schedule B-7. This adjustment effectively reverses the ADIT associated with the cumulative tax deductions on this acquisition adjustment that is included as part of the amounts shown on lines 6 and 7 of Schedule B-7.

Q. Why is it appropriate to adjust ADIT for the NAGD acquisition adjustment?

A. AGD is not permitted to earn a return on the portion of the initial investment of the Southern Union Gas operations that represents the premium paid for the property. This amount is commonly referred to as the "acquisition adjustment" and is maintained on the books of AGD in the amount as ordered by the Commission. As a result of the exclusion of this acquisition adjustment in the Company's rate filing, any ADIT related to the tax deductions taken on this amount should also be excluded from the rate filing. This treatment of ADIT is consistent with the Internal Revenue Code requirements and related regulations that address normalization for rate-regulated utility companies.

Q. Please explain your ADIT adjustment relating to the AFUDC adjustment.

A. Mr. Mason discusses the Commission's Decision No. 61848, adopting a settlement agreement with respect to the treatment of AFUDC and of AFUDC in connection with the Federal Energy Regulatory Commission's ("FERC's") Accounting Release No. 13. The AGD has made an adjustment to reflect the procedures that the Commission adopted in Decision No. 61848. Mr. Doherty has adjusted rate base to reflect the AFUDC modification. Line 12 of Schedule B-7 reduces ADIT consistent with the AFUDC rate base adjustment.

Q. Please explain your adjustment for the excess ADIT for income tax rate changes.

A. The ADIT adjustment on line 4 of Schedule B-7, and reflected in the balance on line 6 of columns [1] through [8] as of December 31,2000, was computed using current income tax rates. That adjustment effectively eliminated any excess ADIT that was reflected in the recorded balances shown on line 1. The adjustment on shown on line 15 reinstates the excess ADIT amounts that were reversed on line 4.

TAXES OTHER THAN INCOME TAXES

Q. Please describe Adjustment H to Schedule C-2, relating to Taxes Other than Income Taxes.

A. Adjustment H is made to the recorded test year level of Taxes Other Than Income Taxes to reflect in cost of service, property taxes and payroll taxes at levels reflective of end-of-year Plant in Service and Materials and Supplies balances, and annualized salaries and wages. This adjustment consists of three pages. The first page is a summary of property and payroll taxes. Page two provides the detail supporting the property tax adjustment and page three provides the detail supporting the payroll tax adjustment.

Q. How was the property tax adjustment computed?

A. It was first necessary to establish the assessed value of the property. The net book values of plant assets and materials and supplies inventories as of December 31, 2001, were reported in a property tax return filed with the Arizona Department of Revenue ("ADOR") in May 2002. Vehicles are not included in the report. Construction Work in Progress ("CWIP") is included, but only at fifty percent of book cost. In June, Citizens received its full cash valuation from the ADOR. Because the property taxes associated with CWIP are required by the FERC Uniform System of Accounts to be capitalized, an equivalent full cash value for use in this adjustment was determined by excluding the portion relating to CWIP. In addition, all of the plant adjustments shown on Schedule B-4A (and discussed in Mr. Doherty's testimony) have been reflected in the net plant in service amount

I use to derive the equivalent full cash value for property tax purposes. The assessment for property tax purposes was computed by multiplying the equivalent full cash value by the current statutory 25% assessment rate.

Once the pro forma property tax assessment was determined, annualized property taxes were computed using the most current known property tax rates. The bills for the property taxes associated with the December 31, 2001, plant will not be received until sometime in September 2003, with the first fifty percent payment not due until November 2003 and the remaining fifty percent due in May 2004. Accordingly, the most recent property tax bills available for use in connection with this adjustment were those paid in November 2001. The average tax rates paid on those bills were applied to the pro forma assessed valuation previously determined to arrive at annualized property tax expense.

Q. How was the adjustment to payroll taxes computed?

A The payroll tax adjustment was computed using the annualized payroll costs computed in Adjustment B, based on current FICA and Federal and State unemployment tax rates. The current FICA tax rate is 7.65%, comprised of 1.45% of taxable wages for Medicare and 6.20% for Social Security. The maximum wages subject to the Social Security portion of the FICA tax increased from $80,400 in 2001 to $84,900 in 2002.

Federal unemployment taxes are computed at a rate of 6.2% on the first $7,000 earnings paid to each employee annually. Citizens receives a credit against its Federal unemployment tax liability for amounts paid to State unemployment funds equal to 5.4% of the first $7,000 annual earnings, which, coincidently, are the wage ceiling and tax rate for Arizona State unemployment taxes.

PRIOR PERIOD TAX REFUNDS

Q. Please describe Adjustment K, relating to Prior Period Tax Refunds.

A. Adjustment K is made to remove from recorded test year Taxes Other Than Income Taxes certain out-of-period and non-recurring items. Included therein are credit entries totaling $1.277 million recorded in connection with applications for sales tax refunds.

In the year 2000, the Company became aware of certain provisions of the Model City Tax Code of the State of Arizona that allowed the Company to apply for a refund of sales taxes paid during the period July 1996 through July 2000 for the communities of Clarkdale, Flagstaff, Jerome, Kingman, Lake Havasu, Sedona, Show Low, Snowflake, and Winslow.

In August 2000, the Company submitted a formal application seeking a refund of approximately $1.98 million for the overpayment of taxes. In May of 2001, the Company received a partial refund totaling $703,658. That amount was credited to Other Income, and at the same time, a receivable for the $1.277 million remainder of the requested refund was established, with the corresponding credit made to Taxes Other than Income Taxes. Adjustment K removes the credits to Taxes Other than Income Taxes, totaling $1.277 million; from test year operating results because the credits in question relate to a prior period.

In addition, Adjustment K reflects other miscellaneous prior period amounts. The total adjustment for prior period amounts is $1,213,112, which is shown on Schedule C-2, page 2 of 2, column 3.

COMPUTATON OF STATE AND FEDERAL INCOME TAXES

Q. Please describe Adjustment S of Schedule C-2.

A. Adjustment S relates to the calculation of state and federal income tax expenses. The current effective state tax rate is 6.968%. The federal tax shown on this schedule, $4,427,136, reflects the current federal tax rate of 35%. Total test year income tax expense has been calculated at both present and proposed rate levels using these tax rates.

Q. Please explain the calculation of the current year federal and state tax expenses.

A. Operating income before income taxes is calculated in Adjustment S, as shown from the data included in Schedule C-1. The interest deduction on line 7 of Adjustment S has been calculated by multiplying the original cost rate base, shown on Schedule B-1, by the weighted embedded cost of debt, shown on Schedule D-1. Tax expenses are then calculated using the currently effective state and federal tax rates.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT
JA-17
admitted

INTRODUCTION

Q. Please state your name and business address.

A. My name is Kevin H. Doherty. My business address is Citizens Communications Company, 3 High Ridge Park, Stamford, Connecticut 06905.

Q. By whom are you employed and in what capacity?

A. I am employed by Citizens Communications Company ("Citizens") as a Regulatory Accounting Manager.

Q. Please describe your current duties and responsibilities.

A. I am responsible for the preparation of regulatory studies for Citizens' Public Service Sector, which includes both the Northern Arizona Gas Division ("NAGD") and the Santa Cruz Gas Division ("SCGD"), collectively referred to as the Arizona Gas Division ("AGD" or "Company"). In addition, periodically I appear in regulatory proceedings on behalf of Citizens, and present testimony and exhibits supporting applications that have been filed.

Q. Please summarize your educational background.

A. I graduated from Pace University in 1987 with a Bachelor of Business Administration degree in Accounting, and I am currently enrolled in Pace University's MBA program. I have attended numerous seminars and presentations that addressed accounting, rates and other financial matters.

Q. Please describe your work experience.

A. From 1987 to 1989, I was employed by Arthur Young and Company as a Staff Auditor. I participated in audits for clients in the manufacturing, energy, and defense industries. I have been employed by Citizens since 1989. From 1989 until 1994, I held the position of Senior Capital Asset Accountant, responsible for preparation of various plant in service and depreciation reports, and I provided data for rate proceedings and certain bond indenture requirements. In 1994, I was promoted to Senior Regulatory Accountant and participated in rate proceedings in the states of Ohio and Illinois. In 1995, I was promoted to Regulatory Specialist, and testified on rate base in rate proceedings in the states of Pennsylvania and Arizona. In 1998, I joined a Citizens-wide team responsible for the implementation of an integrated accounting software system. In 1999, I accepted a position as Manager of Regulatory Accounting. In 2002, I testified in a rate proceeding in the state of Vermont.

Q. What areas will you address in this testimony?

A. I am presenting certain items included in Schedule B of Arizona's standard filing requirements relating to rate base, certain operating expense items included in Schedule C of the standard filing requirements, and all of the financial statements and statistical schedules contained in Schedule E of the standard filing requirements. These schedules were filed as part of this rate application and are found in their own bound volume. With respect to rate base, I will address the following:

- Summary of Rate Base Elements
- Gross Utility Plant in Service
    - Original Cost

  - Reproduction Cost New ("RCN")
- Accumulated Depreciation
- Contributions in Aid of Construction ("CIAC")
- Amortization of CIAC
- Customer Deposits, Materials & Supplies, and Warm Spirit
- Advances in Aid of Construction ("AIAC")
- Gain on Sale of Property
- Y2K Deferred Costs

The summary of all rate base components, including those that I am supporting, is set forth in Schedule B-1, which is described below.

With respect to operating expenses, I am sponsoring Schedule C-1, which shows the recorded, adjusted, and pro forma income statement at present and proposed rates, and Schedule C-2, which summarizes the income statement pro forma adjustments made to the test year. I will also address the following specific adjustments to Schedule C-2:

- Revenue adjustments (Schedule C-2, Adjustment A),
  - Elimination of Unbilled Revenue (Adjustment A-6),
  - Adjustment to Detailed Bill Calculation (Adjustment A-7),
  - Adjustment to Detailed Public Authority Calculation (Adjustment A-8),
  - Elimination of Prior Year PGA Adjustment (Adjustment A-9),
  - Correction for April Revenue, Not Recorded (Adjustment A-10),
  - Miscellaneous Adjustments to Reconcile (Adjustment A-11),

- Uncollectible Expense and Interest on Deposits (Adjustment C),
- Depreciation Expense (Adjustment I),
- Lease Expense for New Office Facilities (Adjustment J),
- Amortization of Gain on Sale of Property (Schedule B-12, Adjustment M),
- Maintenance Expense Related to Gas Supply Line (Adjustment N),
- Y2K Expense (Adjustment O), and
- Postage Expense (Adjustment P).

I will also present Schedule C-3, which computes the Gross Revenue Conversion Factor. As discussed in the testimony of Messrs. Cohen and Smith, Citizens is seeking to consolidate its NAGD and SCGD properties for ratemaking purposes. Therefore, the rate base, revenue, and operating expense adjustments that I am sponsoring were calculated based on the separate recorded amounts for the two properties, and then were combined into the consolidated AGD amounts that are shown on the schedules in this filing.

RATE BASE

Q. Please describe Schedule B-1, containing the Summary of Rate Base Elements.

A. Schedule B-1 summarizes the components of rate base on both a net recorded original cost and a depreciated reproduction new cost basis. The supporting details and calculations of the various components of rate base are contained in subsequent schedules in Section B.

Q. Please discuss Gross Utility Plant in Service.

A. Schedule B-2 is a one-page exhibit that displays the pro forma original cost net plant in service for the test year that ended December 31, 2001. It includes the adjusted plant in service and accumulated depreciation for the AGD that are developed in Schedules B-4A and B-4B, respectively.

Q. Is the Company including any amounts for acquisition adjustments in its revenue requirement in this proceeding?

A. No, it is not.

Q. Where are the amounts associated with the acquisition adjustments reflected on the Company's accounting records?

A. The amounts are shown in Account 114, Plant Acquisition Adjustments, which are not part of the Utility Plant in Service that is included in Account 107.

Q. Did the Company make any adjustments to any rate base or expense elements included in the rate application that are related to the acquisition adjustments?

A. Yes, the Company has removed the Accumulated Deferred Income Taxes ("ADIT") associated with the acquisition adjustment from the recorded ADIT in its application. These adjustments are included on Schedule B-7 and supported by the testimony of Mr. Apuzzo.

Q. Is the Company requesting that any Common Plant be allocated to or from the AGD in this proceeding?

A. No, it is not. Citizens has administrative operations in Stamford, New Orleans and Rochester, where work is conducted for the benefit of the AGD. However, the Company has not included any utility plant in service from these administrative operations in its calculation of rate base in this proceeding, as shown on Schedule B-2, Line 2, and on Schedule B-6. In prior rate cases in Arizona, some of the items included as part of Common Plant have been contested. In addition, the plant value has been sufficiently depreciated so that the net plant amount is not significant when allocated to the AGD in this proceeding. For these reasons, the Company has elected to remove these elements from rate base for this filing. Removing these elements reduces the overall revenue requirement in this proceeding.

Q. Has the Company also excluded Common Plant allocations among its Arizona Operations, such as the gas and electric divisions?

A. Yes, it has. These amounts are small and would tend to offset each other. Again, rather than burden this proceeding with those items, the Company has decided to forego those allocations in this rate proceeding. In general this means that there is no allocation of AGD plant to Citizens' electric operations and no allocation of Citizens' electric plant to its AGD operations.

Q. Please describe Schedule B-3.

A. Schedule B-3 is a one-page exhibit showing the Trended RCN plant and accumulated depreciation for the AGD. The Arizona Constitution requires that the Arizona Corporation Commission ("Commission") set utility rates on the basis of a "fair value". Historically, this was established using a rate base that was equally weighted with net original cost and depreciated reproduction cost new ("RCN"). This schedule complies with that requirement by showing plant and accumulated depreciation calculated by trending original cost to produce a RCN. (In Mr. Mason's testimony, he explains the methodology for deriving the trended RCN plant amounts.) The RCN Plant in Service is brought forward from Schedule B-4, described below. On that schedule, I derive the ratio of depreciable RCN plant to depreciable original cost plant. Multiplying that ratio by the amount of original cost accumulated depreciation (from Schedule B-4B) produces the amount of RCN accumulated depreciation.

Q. What does Schedule B-4 show?

A. Schedule B-4 is a one-page summary exhibit identifying pro forma original cost and RCN as of December 31, 2001, by major plant account. This schedule serves two purposes. First, it shows the detail plant account data that are summarized on Schedule B-1. Second, it shows the detail of the total RCN (on Schedule B-3), consistent with the Arizona constitutional requirement to present a fair value rate base. The original cost plant amounts on Schedule B-4 are developed on Schedule B-4A. The RCN amounts on Schedule B-4 are developed on Schedule B-4C.

Q. Please describe Schedule B-4A.

A. Schedule B-4A starts with the recorded original cost plant amounts, categorized by major plant accounts, and shows the pro forma adjustments to plant in service. Finally, this schedule presents the pro forma plant balance as of the end of the test year.

Q. Please discuss the first pro forma adjustment, relating to the Griffith Transportation Agreement.

A. As Mr. Smith describes in his testimony, Griffith is an electric generating facility with which the NAGD has a contract to provide facilities and certain services for 20 years. The Commission approved the contract between NAGD and Griffith conditioned on the requirement that the NAGD remove all associated revenues, expenses, plant investments and related amounts in any subsequent regulatory proceeding. The NAGD has recorded all Griffith plant under a separate code in the plant accounts to ensure that such plant can be removed in the regulatory process. Similarly, the NAGD has maintained accumulated depreciation under a separate code to permit removal. Adjustment A, Column 3 on Schedule B-4A, reflects adjustments to plant to remove all Griffith-related plant investments. (Schedule B-4B, discussed below, reflects the associated adjustments to accumulated depreciation associated with this and other pro forma plant adjustments.)

Q. Please discuss Adjustment B, Column 4, relating to the SCGD Supply Line.

A. Citizens' Santa Cruz Electric Division ("SCED") owned a gas supply pipeline that was used to provide natural gas to fire its electric generators. SCED has recently transferred this asset to the SCGD to ensure that all gas plant assets are held by the AGD. The assets related to the supply pipeline have been identified, and are included as SCGD plant as shown in Column 4 of Schedule B-4A. The related accumulated depreciation is shown on Schedule B-4B.

Q. Please discuss Adjustment D, in Column 6, Schedule B-4A, relating to the NAGD Paulden Line.

A. NAGD constructed six miles of 8-inch pipeline for the specific purpose of supplying natural gas to NutriSource, LLC, a company that was developing the Paulden Greenhouse Facility for the production of greenhouse tomatoes. Unfortunately, the company's venture was unsuccessful, and NutriSource is no longer in business in Paulden, Arizona. While this pipeline does serve a handful of customers, the AGD has removed this pipeline from plant in service for purposes of this proceeding. Column 6 of Schedule B-4A reflects the removal of the Paulden Line from the plant accounts.

Q. Please discuss Adjustment E in Column 7, relating to Plant Retirements.

A. Following the test year, Citizens conducted a physical inventory of its Arizona General Plant accounts and also made a review of the plant accounting property records to determine if there were any assets on the AGD books that should be retired. As a result of these activities, Citizens determined that approximately 1.1% of total plant, $2.6 million, should be retired. The AGD will formally retire the assets so identified during the current fiscal year. I have reflected these retirements as a reduction to plant in service in Column 7 of Schedule B-4A (and the corresponding symmetric reduction to accumulated depreciation).

Q. Please describe Adjustment F in Column 8, relating to the Yale Street Building.

A. As discussed in Mr. Smith's testimony, as a cost-cutting measure, the AGD recently moved out of its administrative office building located on Yale Street and has moved into a leased facility. Both buildings are located in

Flagstaff, Arizona. The Yale Street building and associated assets have been identified, and I have removed those assets and the related Accumulated Depreciation from Plant in Service in Column 8 of Schedule B-4A and on Schedule B-4B respectively. In addition, Mr. Apuzzo has made an adjustment for the ADIT related to that plant and I have included the lease amount for the new facility as an expense in this proceeding.

Q. Please discuss Adjustment G in Column 9, relating to Allowance for Funds Used During Construction ("AFUDC").

A. As discussed in Mr. Mason's testimony, the Company (as well as other Citizens properties in Arizona) is required to adjust its AFUDC rate consistent with the settlement agreement that the Commission approved in Decision No. 61848, issued July 1999. To conform to the proper procedures outlined in the AFUDC Order, the AGD has revised its test year plant accounts. These revisions are shown in Column 9 of Schedule B-4A.

Q. Please describe the adjustments in Column 11 for Account Corrections.

A. These adjustments reflect the transfers of plant amounts among accounts that result in a zero balance on the total plant line, Line 39. Dr. White, the Company's depreciation expert, has recommended these adjustments as a result of his work in connection with his Depreciation Study.

Q. What is shown on Schedule B-4B?

A. Schedule B-4B starts with the recorded original cost accumulated depreciation, categorized by major plant accounts, and shows the pro forma adjustments corresponding to each of the pro forma plant adjustments contained in Schedule B-4A. Finally, this schedule presents the pro forma accumulated depreciation as of the end of the test year. The adjustment columns (Columns 3-11) mirror the columns as described in connection with Schedule B-4A, above, with the exception of Column 11 for the Account Corrections. This column also includes an adjustment that removes a minor debit balance in Account 365.10. This amount was incorrectly recorded in that account in prior years.

Q. Please describe Schedule B-4C.

A. Page 1 of Schedule B-4C shows the RCN plant amounts, by major plant account and by business area. In addition, the adjustments to plant shown on Schedule B-4A are trended and shown in Column 9. Page 2 of the schedule reflects a summary of the original cost plant in service by each business area that was used to determine the RCN amounts described earlier in my testimony. This is provided to verify that the Company has included all plant in its calculation of the RCN used to determine the Fair Value Rate Base. These amounts exclude the Griffith Plant adjustment.

Q. Please describe Schedule B-8.

A. Schedule B-8 is a one-page exhibit summarizing the rate base deduction for CIAC and related accumulated amortization. This exhibit shows the amount of CIAC, $8,467,783, and Accumulated Amortization, $1,733,000, at the end of the test year.

Q. Does the Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts require that CIAC amounts be offset against plant?

A. Yes, it does.

Q. Does AGD comply with that FERC requirement?

A. Yes. The CIAC amounts are recorded as credits in the plant accounting system and are offset against the related plant amounts. This permits the Company to comply with the FERC requirement and also maintain the gross plant amounts with the related CIAC for presentation in rate applications. The CIAC amounts are shown on a gross basis for rate case presentation purposes and are amortized using the depreciation rates for the related accounts. The annual amortization amounts are offset against the depreciation expense amounts for the plant in compliance with the Commission practice in prior Citizens' rate cases.

Q. What is the CIAC accumulated amortization balance?

A. The CIAC accumulated amortization balance at the end of the test year is $1,733,000, as shown on Column 5 of Schedule B-8. The annual amortization amount is calculated using the approved depreciation rate times the account balance, resulting in $214,928 for the test year, as shown in Column 4 of the schedule.

Q. What is included in Schedule B-9?

A. Schedule B-9 summarizes the monthly balances of several rate base components during the test year. These components are customer deposits, materials and supplies, and the Warm Spirit Program (a low-income program described in Mr. Smith's testimony). Consistent with prior rate cases, the amounts are reflected in rate base using an average of the thirteen monthly balances ending December 31, 2001. A companion adjustment for the annualized interest on customer deposits is included in pro forma test year operating expenses as Adjustment C of Schedule C-2.

Q. Please describe Schedule B-10.

A. Schedule B-10 summarizes the rate base deduction for customer AIAC. AIAC represents amounts of non-investor supplied capital received by the Company and used to fund construction of utility plant.

Q. Please describe Schedule B-12.

A. Schedule B-12 contains a rate base deduction for deferred portions of gains realized from the sales of utility assets. In accordance with Commission policy, when utility assets are sold and removed from the provision of utility service, fifty percent of the after-tax gains are to be shared with ratepayers.

In late 1998, Citizens sold an office building located on San Francisco Street in Flagstaff to a non-utility purchaser. The building would no longer be useful or necessary in providing utility service. The transaction produced an after-tax gain totaling $140,650. Fifty percent of that amount was credited to a regulatory liability pending its disposition in the next rate case.

In November 2001, Citizens sold an office building in Cottonwood. That building was also removed from utility service. That sale produced an after-tax gain of $68,212. Fifty percent of that amount was credited to a regulatory liability pending disposition in the next rate case.

Q. What treatment does the Company propose for these gains on sale?

A. The AGD proposes to amortize the combined $104,431 deferred customer share of the gains from the property sales over a period of five years and reduce rate base by the unamortized amount. Accordingly, in this application, rate base is reduced by $104,431, with a corresponding negative amortization of $20,886 reflected in operating expense as Adjustment M on Schedule C-2.

Q. Please discuss the adjustment for Y2K costs.

A. This adjustment relates to the Company's allocated portion of Citizens' expenses incurred with becoming Y2K compliant. It is the corresponding rate base amount associated with the amortization described as Adjustment O to Schedule C-2, below. The Y2K costs and recovery that is being sought are discussed in more detail later in my testimony.

OPERATING INCOME

Q. What is shown on Schedule C-1?

A. Schedule C-1 contains the income statement for the test year ended December 31, 2001. Recorded amounts, pro forma adjustments for known and measurable changes, and the resulting pro forma test year amounts are shown for revenues, by class of service, and for operating revenue deductions by major function. The schedule also includes the effect of the requested revenue increase and the adjusted test year income statement at proposed rates.

Q. Please explain briefly the computation of pro forma test year revenues and expenses.

A. The ratemaking process involves the determination of a utility's revenue requirement based on a test year that reflects a level of operating revenues and expenses and net plant investment that is representative of normal conditions, free of any distortions. The rates to be derived are not necessarily intended to recover specific test year costs, but rather, similar costs expected to be incurred in the future.

Pro forma adjustments are made to address any revenues or expenses that are not representative of the levels expected to occur during the period in which the new rates will be in effect. Such adjustments may be in the form of eliminations, annualizations, or normalizations.

Q. What are elimination, annualization, and normalization adjustments?

A. Elimination adjustments are made to remove out-of-period items or items that are not costs or revenues related to the provision of utility service; thus, not includible in revenue requirements.

Annualization adjustments are made to reflect the full, twelve-month revenue or expense level of certain items of operating income. Examples include restating test year revenues to reflect customer levels at the end of the test year, adjusting payroll expense for the effect of salary adjustments or changes in employee levels since the beginning of the test year, and adjusting recorded depreciation expense to reflect the full effect of plant additions and retirements during the test year.

Some costs that may be included in revenue requirements are incurred at intervals less frequently than annually, provide benefits extending beyond a single year, or reoccur in significantly different amounts each year. As a result, the amount recorded in the test year may not be viewed as "normal." Normalization adjustments are made when a test year level of revenues or expenses is not representative of what would be expected on an on-going basis. Examples include rate case expenses, bad debts expense, and the overtime percentage used in computing pro forma payroll expenses.

Q. Please describe Schedule C-2.

A. Schedule C-2 consists of 19 income statement adjustments. The first two pages, (labeled "Page 1 of 2" and "Page 2 of 2") summarize the pro forma adjustments appearing on Schedule C-1, column 5. The remaining pages show the detail of each pro forma adjustment that is reflected on the first two pages of Schedule C-2. Each of those pages is identified by the adjustment letter that corresponds to the letter shown below the column numbers on Schedule C-2, pages 1 and 2.

REVENUE ADJUSTMENTS

Q. What is the purpose of Adjustment A of Schedule C-2?

A. Adjustment A consists of eleven items that increase or decrease recorded test year revenues. The adjustments are a combination of Commission-mandated filing requirements, as well as the normal adjustments made to recorded test year operating revenue. It should be noted that the revenues in column 1 of Schedule C-1 (to which the Schedule C-2 revenue adjustments are made) already reflect the removal of the Griffith revenues (shown on Schedule E-6B).

Q. Please describe the process used to determine if adjustments were required.

A. First, we reviewed the recorded revenues for the NAGD and the SCGD to determine the amounts of revenue from monthly customer billings as reflected on the Monthly Revenue Analysis ("MRA") and the amounts derived from other journal entries. Next, we developed a Bill Frequency Analysis ("BFA") for each property, and compared those analyses with the monthly customer billing amounts. Finally, Mr. Harrison, the Company's rate design witness, adjusted recorded revenues, where necessary, to reflect a normal test year for ratemaking in its presentation.

Q. Please describe the first revenue adjustment contained on Adjustment A of Schedule C-2.

A. The reclassification of revenues for the SCGD, shown on Line 2, reflects the identification of customers to be included in the Public Authority and Industrial classifications. SCGD personnel identified these customers, originally included in the Commercial class, to fit the criteria of the Public Authority and Industrial classes, which are new to the SCGD, and to conform to those at the NAGD. Because both properties will have the same tariffs, it was necessary to reclassify the revenue and associated billing determinants for these customers. This reclassification does not change the total revenue amounts.

Q. Please describe Adjustment A-1.

A. Adjustment A-1 on Line 3 removes all gas costs from the revenues of the AGD. The detail of this adjustment is shown on Page 2. The AGD revenue requirement is determined on a Gross Margin basis, because gas costs are primarily recovered through operation of the Purchase Gas Adjustor ("PGA") for each property.

Q. What is reflected in Adjustment A-2?

A. Adjustment A-2 on Line 4 removes the New Service Area Multiple ("NSAM") revenues from the recorded amounts. At its September 13, 2001 Open Meeting addressing the Company's PGA surcharge request, the Commission directed the NAGD to cease billing the NSAM when it concluded its Build Out Program (then expected to occur early in 2002). The NAGD notified the Commission that its Build Out Program and NSAM would terminate as of January 1, 2002. Because the NAGD is no longer collecting this charge, the associated revenues need to be eliminated from recorded amounts for the test year. Mr. Harrison's testimony supports the calculation of this amount, which is removed on Schedule C-2.

Q. Please describe Adjustment A-3.

A. Adjustment A-3 on Line 5 reflects the adjustment to gross revenues to weather normalize the recorded revenues. Related gas costs are shown on page 2 and are included in the gas costs removed in Adjustment A-1. Mr. Harrison supports both of these amounts in his direct testimony.

Q. What does Adjustment A-4 show?

A. Adjustment A-4 on Line 6 shows the gross revenue amounts necessary to reflect customer levels at the end of the test year. Related gas costs are shown on page 2 and are included in the gas costs removed in Adjustment A-1. Mr. Harrison supports both of these amounts in his direct testimony.

Q. Please describe Adjustment A-5.

A. Adjustment A-5 increases revenues for the "Tariff 32" revenues. The BFA identified a difference between the detailed billing determinants for this tariff class and the recorded amounts. After a review by the NAGD personnel, it was determined that the recorded revenues were understated and needed to be increased for the test year.

Q. What is Adjustment A-6?

A. Adjustment A-6 on line 8 increases recorded revenues by removing the amount of unbilled revenues reflected by the AGD at the end of the test year, which is December 31, 2001. This adjustment is necessary since Mr. Harrison's adjustment for weather normalization, shown as Adjustment A-3, includes an adjustment to account for unbilled revenues.

Q. Please describe Adjustments A-7, A-8, and A-9.

A. Like Adjustment A-5, these minor adjustments conform recorded revenue amounts to those recorded in the MRA for the calendar year. These adjustments represent prior period adjustments or corrections to restate the test year revenues to be consistent with the sales and costs occurring in the test period. Mr. Harrison compares these revenues with those calculated by multiplying the existing rates and billing determinants. He computes a booked-to-billed ratio for each rate class in order to develop appropriate rates. The approach replaces the reconciling percentage adjustment normally used in rate cases to conform the recorded to the calculated revenue amounts.

Q. Please describe Adjustment A-10.

A. Adjustment A-10 reflects the amount of an adjustment to NAGD revenues that NAGD personnel identified in May 2001, but that did not get recorded on that property's books. This amount represents revenues received in April 2001 that, because of a change in meter reading schedules, were not included in the initial April summary of revenues reported to Accounting for April revenues. When the adjustment for these April 2001 revenues was reported after the monthly close, it was not included in the revenues for May 2001. Accordingly, recorded revenues for the test year are understated. This adjustment increases recorded revenues for this proceeding. The amounts at issue will be recorded in 2002.

Q. What does page 2 of Schedule C-2, Adjustment A show?

A. Page 2 of Adjustment A reflects the gas costs related to each of the recorded revenues and revenue adjustments shown on Adjustment A, page 1. The Company has shown both the gross revenue (on page 1) and the gas costs (on page 2) for each adjustment to facilitate review.

OPERATING EXPENSES

Q. Please address the first operating expense item that you are sponsoring, relating to Uncollectible Expense and Interest on Deposits.

A. Adjustment C reduces recorded test year bad debts expense and includes in operating expenses the annualized interest on customers' deposits.

The uncollectible, or bad debts, portion of Adjustment C reduces the test year recorded expense amount to a level reflective of pro forma adjusted customer-annualized, weather-normalized test year revenues and of the average level of account write-offs, net of subsequent recoveries, experienced during the past three years. Since the portion of customer bills for the base cost of gas and the PGA are subject to write-off, such amounts have been added to the computational base.

The portion of Adjustment C relating to interest on customer deposits is related to the deduction of customer deposits from rate base, discussed in connection with Schedule B-9. It reflects the fact that such interest is typically recorded as a component of Other Interest Expense, which would not afford the Company the opportunity to recover such costs through the ratemaking process, absent this reclassification to operating expenses. The adjustment was computed based on the end-of-year balance of customer deposits and the prescribed rate of 6%.

Q. Please discuss Adjustment I, relating to Depreciation Expense.

A. Adjustment I in Schedule C-2 sets forth, by prime account, the AGD's adjusted depreciation expense for the test year using the adjusted plant balance as of December 31, 2001, and the depreciation rates proposed by Dr. White. These factors result in a significant decrease to the AGD's depreciation expense.

Q. Please describe the next operating expense item, relating to Lease Expense for New Office Facilities.

A. As noted above, subsequent to the test year, the AGD personnel relocated from the administrative office building located on Yale Street in Flagstaff, to a leased facility. This was a part of a cost-cutting approach adopted by AGD. Pro forma Adjustment J reflects the annual lease expense that is a known and measurable cost that the Company will incur. This adjustment is related to the adjustment removing the net Yale Street assets from rate base.

Q. Is there any gain that will be recognized from the eventual sale of the Yale Street facility?

A. The Company estimates that the Yale Street facility will be sold at a loss or, at best for an amount equal to the net book value of the assets to be sold, which will result in no gain.

Q. Please discuss Adjustment M, showing the Amortization on Gain on Sale of Property.

A. This Adjustment is the expense adjustment that corresponds to the rate base adjustment on Schedule B-12, as discussed above.

Q. What is Adjustment N, Maintenance Expense Related to Gas Supply Line?

A. As discussed above in connection with Adjustment B to Schedule B-4A, Commission approval has been requested to transfer a gas supply pipeline from the SCED to the SCGD. The amounts shown on Adjustment N represent the Company's estimate of expenses the AGD will incur to maintain that gas supply line.

Q. What does Adjustment O, relating to Y2K, represent?

A. Adjustment O reflects the AGD's allocation of expenses that Citizens incurred in connection with becoming Y2K compliant. On December 7, 1998, on behalf of all of its Arizona properties, Citizens filed a request with the Commission seeking an accounting order permitting the deferral (for future regulatory consideration) of costs Citizens incurred for Y2K activities. On January 29, 1999, the Commission issued Decision No. 61382, approving the Citizens' request. In accordance with that Decision, the AGD has been deferring the expenses incurred in connection with Y2K in a special regulatory asset account.

Q. Please describe Adjustment O.

A. Adjustment O shows the total (allocated) costs that the AGD incurred for Y2K activities. I have removed from the total the internal AGD payroll expenses associated with Y2K, since those costs are already included in payroll expense.

Q. Over what period does the Company propose to amortize these Y2K expenses?

A. The AGD proposes to amortize the deferred Y2K expenses over five years. Therefore, the Company has included one-fifth of the total adjusted balance as pro forma test year operating expense adjustment. The unamortized balance of Y2K costs is included in rate base on Schedule B-1.

Q. Please explain the Postage Expense adjustment.

A. The United States Postal Service has increased the cost of several classes of postage, effective June 30, 2002. Of relevance to this proceeding, bulk rates have increased 2.3 cents for both mail that the Company sorts by five-digit zip code and by the first three digits of the zip code. These represent the two applicable rates for AGD bills. To derive the amount of this adjustment, I multiplied the postal rate increase by the annual number of bills (based on customer levels at the end of the test year). Adjustment P increases test year postage expense by $33,130 to reflect this known and measurable change.

Q. What is the Gross Revenue Conversion Faction shown on Schedule C-3?

A. Once the Company calculates the operating income deficiency, it is necessary to convert that deficiency to the equivalent annual increase in revenues by use of the Gross Revenue Conversion Factor. This factor is necessary to reflect the fact that the additional revenues requested in this application will generate additional bad debts expenses, Federal and State income taxes, and other revenue-driven expenses. The Company must perform this gross-up procedure to ensure that, after deducting the additional taxes and other revenue-driven expenses from the additional revenues, the resulting incremental net operating income is equal to the computed revenue deficiency.

HISTORIC FINANCIAL DATA

Q. What information is contained in Section E of this rate application?

A. Section E contains a variety of recorded historical financial and statistical data for the AGD for the test year ended December 31, 2001, and for the years ended December 31, 2000, and December 31, 1999. In addition, this section contains the notes to the financial statements and certain operating statistics.

COMPARATIVE SCHEDULES

Q. Would you please describe each of the schedules contained in Section E?

A. Schedule E-1 shows the AGD's comparative balance sheets. Schedule E-2 contains the AGD's comparative income statement and Schedule E-3 shows the AGD's comparative statements of changes in financial position. Schedule E-4 would require a statement of changes in stockholders' equity. Since the AGD is a division of Citizens, Schedule E-4 is not applicable to the AGD. Schedule E-5 shows the detail of utility plant in service at December 31, 1999, December 31, 2000, and December 31, 2001, as well as net plant additions. Schedule E-6 shows the comparative operating income statements in detail, setting forth revenues by class of service and operating revenue deductions by major categories. Schedule E-7 presents various operating statistics for the AGD. Schedule E-8 details taxes charged to the operation. The notes to the preceding financial statements are presented on Schedule E-9.

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

EXHIBIT
JA-18
admitted

CITIZENS COMMUNICATIONS COMPANY

ARIZONA GAS DIVISION

TESTIMONY OF ROBERT G. ROSENBERG

JULY 2002

INDEX

I. INTRODUCTION

Q. Will you give your name, business address and occupation?

A. My name is Robert G. Rosenberg. My business address is 541 Bear Ladder Road, West Fulton, New York. I am an economist and principal of the firm of Edgewood Consulting, Inc. My qualifications are described in Exhibit RGR-1 to this testimony.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to determine the cost of capital for the Northern Arizona Gas Division ("NAGD") and the Santa Cruz Gas Division ("SCGD") of Citizens Communications Company ("Citizens"). Collectively these companies comprise Citizens' Arizona Gas Division ("AGD"). I have been advised that as part of this case, Citizens is requesting that NAGD and SCGD be consolidated for ratemaking and other purposes.

Q. Would you provide an overview as to how you testimony will be organized?

A. I will determine the cost of equity for AGD and then will develop the overall cost of capital.

In my determination of the cost of equity, I will first discuss the rationale for using several equity costing methodologies. Next I will address the need to use proxy companies to develop the cost of equity of AGD. I will then calculate the cost of equity using four methodologies: the Discounted Cash Flow approach, the Capital Asset Pricing Model, the risk premium approach and the comparable earnings analysis. Finally I will develop and recommend a cost of equity to be used in this proceeding.

In developing an overall cost of capital, I will first determine an appropriate capital structure for AGD. I then analyze the appropriate cost of debt to be used along with the cost of equity I determine in this testimony. Finally, I recommend an overall cost of capital for AGD in this proceeding.

Q. Have you prepared any exhibits in conjunction with your testimony?

A. Yes. In support of my testimony, I have prepared Exhibits RGR-1 through RGR-7.

Q. Were these exhibits prepared by you or under your supervision?

A. Yes, they were.

II. ESTIMATION OF THE COST OF EQUITY

A. Rationale for Using Several Equity Costing Methodologies

Q. Do you believe it is reasonable to employ several approaches for estimating the cost of equity?

A. Yes. The cost of equity is not directly observable in the marketplace. Therefore, to estimate the cost of equity, one must take cognizance of financial theory, the legal and regulatory framework for ratemaking and investor perceptions and judgments. There is no one approach that is now recognized, or should be recognized, as the way to determine the cost of equity. The Commission indicated at page 19 of its October 30, 2001 Decision No. 64172 concerning Southwest Gas Corporation that:

> All of the capital experts testifying in this case have impressive credentials. One thing they all agree on is that it is important to utilize a variety of financial models to derive a cost of equity. Each model has its strengths and drawbacks.

Moreover, I believe that currently there is the potential for more error of estimation than normal in determining the cost of equity of a utility.

Q. Why do you believe that presently there is a potential for large measurement error associated in determining the cost of equity for utilities?

A. While it was always good financial practice to employ several methods to estimate the cost of equity in order to reduce measurement error associated with any particular methodology, that notion has special relevance today. The assessment of utility risk and potential performance is in flux currently due to the uncertainties associated with regulatory restructuring, competitive developments and consolidation in the industry. *The Value Line Investment Survey*, in its December 21, 2001 writeup of the gas distribution industry stated that:

> It is important to consider, however, that the entire energy industry, spurred by deregulation, is undergoing rapid change.

Standard & Poor's, at page 3 of its November 29, 2001 *Natural Gas Distribution Industry Survey*, stated that:

> ...the natural gas industry is still in the midst of a significant transition. The change involves not only consolidation within the industry, but even more significantly, the ongoing convergence of the natural gas business and an equally transformed electric utility industry.

S&P indicated on page 7 of the same publication that:

> The natural gas industry has undergone substantial change over the past decade. Gas utilities, which were once tightly regulated monopolies, have slowly been opening to regional competition. As state and federal public utility commissions continue to restructure the regulatory environment, the natural gas distribution

> industry is likely to be further transformed over the next several years.

Therefore, when we attempt to estimate the cost of equity for a particular utility, this state of flux is likely to lead to more estimation error than under circumstances in which that company's more easily forecasted fundamentals are the prime determinant of its stock prices and where that company's risk seems clearly delineated to investors.

Q. What conclusion do you reach from the above discussion?

A. As I indicated above, because I believe that there is more error of estimation than normal in determining the cost of equity of a gas distribution utility, I will employ several different analyses in this proceeding. Such an approach leads to a broader-based set of estimates and will prevent any spurious results from biasing the cost of equity determination.

Q. What methods do you use in this proceeding to estimate the cost of common equity capital?

A. I will employ four separate approaches including: (1) a discounted cash flow ("DCF") analysis; (2) a capital asset pricing model ("CAPM") analysis; (3) two risk premium analyses; and (4) a comparable earnings analysis.

B. Use of Comparison Companies to Determine the Cost of Equity of AGD

Q. Can you review the circumstances regarding AGD currently which supports the use of a proxy group?

A. AGD is a division of Citizens and therefore has no publicly traded stock. Citizens is currently primarily a telecommunications company. *The Value Line Investment Survey* assigns Citizens to the Telecommunications Services Industry. For the Year 2001, only about 17 percent of Citizens' revenues came from gas distribution operations and only about a quarter of Citizens' revenues were attributable to electric and gas operations.

To date, Citizens has sold its Colorado and Louisiana gas operations, as well as all of its water and wastewater operations. Citizens has announced a policy of divesting its remaining utility (gas and electric) operations. In fact, the Chairman's letter in the 2001 Annual Report indicated that Citizens expects to enter into sales agreements for these properties during this year. Citizens indicates in its financial statements that its gas distribution assets, including NAGD and SCGD, are classified on its books as "assets held for sale" in the "current assets" section of the balance sheet. In addition to divesting water and utility operations, Citizens has been acquiring telecommunications assets and has greatly changed its capital structure in the process. Value Line estimates that Citizens will have a common equity ratio of only about 26 percent at the end of 2002—a level that is certainly not typical for a gas distribution utility.[1]

In the past, the Commission has differentiated between Citizens and its Arizona utility operations, viewed on a stand-alone basis. At page 21 in its 1997

[1] As indicated later in this testimony, Citizens' current equity ratio is not typical for a telecommunications services company either.

Decision No. 59951 regarding Citizens' Arizona Electric Division, the Commission noted, with respect to the appropriate income tax rate, that:

> The Company utilized the actual 35 percent income tax rate that its parent paid during the [Test Year]. Both RUCO and Staff applied a 34 percent rate with the rationale that on a stand-alone basis, the Company would have less than $10 million in income.... On a stand-alone basis, the Company would fall into the 34 percent federal tax bracket and that is the rate recommended by Staff and RUCO. The Company proposed a 35 percent tax rate to reflect a consolidated corporate basis tax rate.... We find Staff and RUCO's recommendations to utilize a 34 percent rate to be reasonable under the circumstances.

For all the above-cited reasons, it is inappropriate to use Citizens' total company data in order to estimate the cost of capital for AGD, which is a regulated gas distribution utility. Rather, it is my judgment that it is appropriate to use a proxy—a group of comparison companies—to obtain an estimate of the cost of equity of AGD. As further support for the use of a proxy group, I note that the touchstone U.S. Supreme Court decisions, Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944) ("Hope") and Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923) ("Bluefield"), indicated that a fair rate of return to a regulated company is, in part, one that is equal to that earned in enterprises of similar risk.

Given the circumstances and the support cited above, I will employ a group of proxy companies in order to estimate the cost of equity of AGD in this proceeding.

Q. Would you indicate how you selected the group of proxy companies upon which you conducted your cost of equity analysis?

A. I started by considering companies that were listed in *The Value Line Investment Survey*'s gas distribution utility category and applied three further selection criteria to these companies. First, companies were excluded from the proxy group if they had significant unregulated operations. Since unregulated operations potentially have different risk from regulated utility operations, this criterion ensures that the companies in the proxy group have predominantly regulated utility operations. Second, companies were excluded from the proxy group if they are currently involved in any major merger activity. Removing companies with merger activity from the cost of equity calculation eliminates companies whose prices and evaluations may be based on short-term merger-related considerations, rather than the long-term prospects of the company. As I explain in more detail in the discussion of the DCF methodology, merger activity has the potential for biasing the DCF result in a potentially significant manner. Third, companies were also excluded from the proxy group if they are not currently paying a dividend or recently had a dividend reduction. Such circumstances make cost of equity estimation using the DCF approach problematic.

The list of companies in the proxy group is shown on Exhibit RGR-2.

Q. How does the size of the gas distribution utility companies in your proxy group compare with AGD?

A. The average and median revenues for Year 2001 for the proxy group were about $1.4 billion, while AGD had revenues of about $70 million (rounded). The smallest company in my proxy group (Cascade Natural Gas) had revenues about five times the size of AGD. As noted above, I selected companies that were included in Value Line's gas distribution utility category. Companies are listed in Value Line because they are publicly traded and are of sufficient size to be of interest, in Value Line's opinion, to the investment community. Thus, it is a fact of life that any of the companies covered by Value Line—thereby having publicly available data that can be used in equity costing calculations—will be significantly larger than AGD. While it is not possible to exactly match proxy group companies to AGD on a size basis, I believe that the selection criteria I apply, ensemble, result in a group of companies reasonably comparable in risk to AGD.

C. DCF Analysis

Q. Before proceeding with the presentation of the DCF analysis for estimating the cost of equity, please give a general description of the DCF method.

A. This method produces an estimate of the market-required return based upon investor evaluation of a company's earnings and dividends, as reflected by the prices that investors pay in the stock market. Basic DCF theory is predicated on the notion that the price that is paid for a company's stock in the market represents the sum of the present value of all future expected dividends. Algebraically, this can be written as:

$$(1) \quad P_0 = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \frac{D_4}{(1+k)^4} + \cdots$$

where: P_0 = the recent price of the stock

D = the expected dividend for the period specified

k = the investors' discount rate, or required rate of return (expressed in decimal form, *e.g.*, 0.15)

The dots at the end of this formula indicate that the equation continues to infinity—in other words, the next two terms would be $D_5/(1+k)^5$ and $D_6/(1+k)^6$, and so on. The above formula indicates that investors establish the price they are willing to pay for a stock based upon the expected future stream of dividends, discounted back to the present time.

Q. Please discuss the potential for large measurement error associated with the DCF at the present time that you mention earlier in your testimony.

A. To apply the DCF method, needed elements include the price that investors are paying for a stock in the marketplace and a reliable estimate of the growth expectations that led investors to bid the observed price. If investors' growth expectations have been correctly estimated, then such estimate is congruent with the market price. If all the factors influencing the market price are not reflected in the growth estimate used by an analyst, then measurement error is introduced into the DCF analysis and the resulting cost of equity estimate will be biased.

As can be seen from the formulation presented above, in order to correctly assess investors' required return in a DCF context, one must ascertain the dividend stream that investors are expecting over the long run. Analysts typically do this in a framework of estimating constant expected growth (if the future is expected to be relatively stable) or multiple stages of growth (if there is an expectation that growth may change in the future). It is my opinion that the DCF method is more prone to measurement error currently due to a lack of congruence between the market price and the growth estimate employed because of a lessening of the clarity of investor growth expectations. As I noted earlier, many companies in the industry are in flux currently, transitioning to a restructured environment where the final rules have not yet been carved in stone.

Typically, investment analysts provide five-year growth projections for the companies they cover and investors often employ these projections as their expected growth in the future. However, given the changes occurring in the industry, these five-year projections are not good proxies for the long-term expected growth for utilities at the current time. Certain utilities have been assuming a more conservative payout policy either to address the need for more internally generated cash flow or to help deal with the higher risk of earnings fluctuations. Some gas distribution utility managements are engaged in common stock buy-back programs. This near-term phenomenon of stock buybacks creates a short-term demand for the stock, which raises stock prices above what they would have been, absent the buyback plan.[2]

Investors are also aware that numerous mergers have occurred in the gas distribution utility industry and more are likely to occur in the near future. In a report entitled "U.S. Gas Distributors Weather Higher Prices, Other Issues" dated July 13, 2001, Standard & Poor's indicated that:

> In the past few years, about 20 mergers have been announced or closed, involving local gas distribution companies...totaling about $22 billion.

As a result of mergers, *The Value Line Investment Survey* covers about 20 percent fewer gas distribution companies than it did just two years ago. On page 7 of its November 29, 2001 *Natural Gas Distribution Industry Survey*, S&P stated that:

> In Standard & Poor's view, mergers between members of the natural gas and electric power industries will continue to occur. Along with each industry's competitive evolution and consolidation, the combination of gas and electric companies has become a significant trend over the past few years.

The potential for additional mergers could influence investor expectations in three ways. First, mergers have generally occurred at a premium above the pre-merger-announcement market price, leading to capital gains for investors. Second, mergers can result in increases in the dividend received by investors. Third, investors may see mergers as a win-win situation—offering both rate reductions to

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[2] This is simply because, in a rising market, the fact that a company, itself, is buying back stock merely adds to the buying pressure already in effect from a buoyant market. If investors think that stock prices might decline, the fact that the company is likely to be a large-scale buyer in a weak market would certainly provide investors with a cushion. Given both of these effects, stock buybacks would raise the price of a utility's stock above what it would be otherwise. Stock buyback plans often are implemented over a number of years. Thus any accretion in growth resulting from the buyback will be expected to be phased in gradually over time.

ratepayers and enhanced return prospects for stockholders. To the extent that there is speculation about future merger activity among utilities, such influence would be reflected in the price, but not in the growth projections made by analysts. The effect on the DCF of such speculation would be to bias the cost of equity estimate downward (due to the mismatch between the merger-speculation-inflated price and business-as-usual growth estimates).

Therefore, because of the complex set of phenomena currently affecting utility stock prices, a DCF estimate will have the potential for more measurement error than DCF calculations performed in the past under more stable circumstances where investor expectations were determined with more certainty.

Q. Given the difficulties you outline above, how will you proceed with implementing the DCF approach for determining the cost of equity for the comparison companies?

A. The use of the constant-growth DCF formulation (D/P + g) for a regulated utility often may have been a reasonable assumption in the past when the financial and regulatory environment in which regulated utilities operated was more stable than currently. During that time, trends could reasonably be expected to continue and long-term future growth could be predicted with substantial accuracy. However, as established earlier in this testimony, the utility industry currently is in a state of flux. In light of this, I will employ a two-stage DCF approach to estimate the cost of equity of the comparison companies.

Q. How did you determine the appropriate pricing period for your DCF analysis?

A. The price component of the DCF analysis should reflect recent data over a representative period of time that is neither so short as to merely represent the "luck of the draw" nor so long as to encompass stale data. The pricing period should be long enough to smooth out the effects of any temporary market fluctuations. In the DCF analysis, I will employ a pricing period encompassing the six months ending March 2002.

On Exhibit RGR-3, I show the average prices for the comparison companies over the six-month period ending March 2002. Each month's price was calculated by averaging the monthly high and low prices. The six-month average price is also shown in Column (1) of all three pages of Exhibit RGR-4, which provides the inputs to the DCF calculation. The indicated dividend level (*i.e.*, the quarterly dividends paid during the pricing period, annualized) for each of the comparison companies shown in Column (2) of all three pages of Exhibit RGR-4.

Q. How do you determine the expected growth component of the DCF model for the comparison companies?

A. As noted above, given the regulatory, competitive, risk, payout policy, and other changes noted above, it is difficult to ascertain, with great clarity, investor growth expectations at the current time. I will employ a two-stage growth formulation of the DCF method to estimate investors' future growth expectations. For the determination of near-term (*i.e.*, first-stage) growth, I rely on an average of earnings projections made by Value Line and the Institutional Brokers Estimate System ("IBES"). These projections for the comparison companies and the average of the two are shown in Columns (3)-(5) of Exhibit RGR-4, pages 1-3.

The estimation of second-stage, long-term growth is more problematic. I am not aware of any specific projections that are made by financial analysts for this timeframe. However, I will employ three proxies for investors' expected long-term growth.

First, I will employ the long-term projected nominal Gross Domestic Product ("GDP") growth as a proxy for expected long-term second-stage growth for an individual company.[3] The Energy Information Administration ("EIA") of the Department of Energy published the *Annual Energy Outlook 2002* which contains data that can be used to derive a long-term projection of growth in nominal GDP. Using data from that source, I have calculated projected growth in GDP for the period 2007-2020 to be 6.19 percent. The long-term projected growth in GDP is shown in Column (6) on Exhibit RGR-4, page 1.

For the second proxy for investors' expected long-term growth, I employ the Value Line projection for the 2005-2007 period for retention growth.[4] The projected retention growth rates are shown in Column (6) on Exhibit RGR-4, page 2.

For the third estimate of investors' expected long-term growth, I employ a projection of expected industry growth. Given the competitive and regulatory

[3] In the absence of a clear picture of long-term future growth specific to gas distribution utilities, investors might employ a generalized measure of economy-wide growth as a proxy for expected utility growth.

[4] Value Line specifically labels this growth rate as "Retained to Common Equity." This growth rate reflects Value Line's projection of the growth a company will experience from retaining earnings from year-to-year. This type of growth is also known as retention growth or internal growth.

uncertainties facing utilities, discussed above, investors might look at projected industry growth as a proxy for projected long-term growth for individual companies. Zacks, Value Line, S&P and IBES project growth for the industry to be 7.6, 5.0, 7.1 and 8.0 percent, respectively. As a proxy for projected industry growth, I will use a figure of 6.5 percent. This proxy for projected long-term industry growth is shown in Column (6) on Exhibit RGR-4, page 3.

Q. Would you review the components of the two-stage DCF analyses for the comparison companies?

A. The DCF analyses using GDP growth, retention growth and industry growth are shown on Exhibit RGR-4, pages 1, 2 and 3, respectively. Columns (1) and (2) of page 1 of Exhibit RGR-4 show the 6-month average price and the indicated dividend for the comparison companies. Columns (3)-(5) show the Value Line, IBES and average projected earnings growth rates. Column (6) of Exhibit RGR-4, page 1, shows the long-term projected growth in GDP, which is assumed to occur after the first-stage growth period. Column (7) of Exhibit RGR-4, page 1 shows the DCF cost of equity estimate for each company calculated by an iterative process employing the internal rate of return. (For calculational purposes, I continue the second-stage growth for 200 years because any growth after that point has a negligible effect on any present value or internal rate of return calculation.)

Page 2 of Exhibit RGR-4 shows the two-stage DCF analysis employing projected retention growth for the long-term expected growth rate. Columns (1)-(5) show the same inputs as on page 1 of Exhibit RGR-4. Column (6) of page 2 of Exhibit RGR-4 shows the projected retention growth, which I employ as the long-term projected growth assumed to occur after the first-stage growth period. Column (7) of page 2 of Exhibit RGR-4 shows the DCF cost of equity estimate for each company. Page 3 of Exhibit RGR-4 shows the two-stage DCF analysis employing projected industry growth for the long-term expected growth rate. Columns (1)-(5) show the same inputs as on pages 1 and 2 of Exhibit RGR-4. Column (6) of page 3 of Exhibit RGR-4 shows the projected industry growth, which I employ as the long-term projected growth assumed to occur after the first-stage growth period. Column (7) of page 3 of Exhibit RGR-4 shows the DCF cost of equity estimate for each company.

Q. What are the results of your DCF calculations?

A. As shown in Column (7) of page 1 of Exhibit RGR-4, the median DCF results using the projected GDP growth as the long-term growth estimate was 11.2 percent. Using the projected retention growth as the long-term growth estimate, the median DCF cost of equity result was 11.5 percent, as shown in Column (7) of page 2 of Exhibit RGR-4. Employing projected industry growth as the long-term growth estimate, the median DCF cost of equity result was 11.5 percent, as shown in Column (7) of Page 3 of Exhibit RGR-4. Based on these results, I will use a DCF cost of equity range of 11.25-11.50 percent in my subsequent analysis. Taking into account my discussion, above, concerning the measurement difficulties associated with the application of the DCF method currently, it is my opinion that these results should be considered in conjunction with the results of the other methods I employ.

D. CAPM Analysis

Q. What is the basis of the CAPM approach you will employ?

A. Assuming rationality on the part of investors, the greater the risk of an investment, the higher the return that investors will demand of that investment. The yield on risk-free assets such as U.S. Treasury securities is readily determinable in the marketplace. Given that fact, if we know the risk premium that investors require to invest in the stock of the comparison companies rather than a U.S. Treasury security, we can determine the required rate of return, or cost of common equity, for the comparison companies. In this section of my testimony, I will employ the CAPM method to calculate this risk premium and the cost of equity for the comparison companies.

Q. Would you briefly outline the theory underlying the CAPM method?

A. In recent developments in financial theory, the total risk (variance) of an asset has been partitioned into two components: unsystematic risk and systematic risk. Unsystematic risk represents risk (*i.e.*, fluctuations in returns) due to events specific to the particular company in question (*e.g.*, a long strike at the company's plants; the loss of a large government contract; the release of a highly profitable motion picture, etc.). Unsystematic risk is company-specific and is unrelated to changes in the economy as a whole. Systematic risk, on the other hand, represents the variability in the returns on an investment due to the effect on the firm of economy-wide forces. The level of a firm's systematic risk is determined by the firm's sensitivity to the totality of macroeconomic forces in the economy.

Modern financial theory calls for the evaluation of an asset, not in isolation, but in the context of a well-diversified portfolio. If enough stocks are held in a well-diversified portfolio, the firm-specific (unsystematic) risks of the individual firms will tend to cancel each other out. The theory is that if there are enough assets in the portfolio from diverse industries, some of the assets will experience higher than expected returns while other assets will experience lower than expected returns, but the portfolio as a whole will yield the average expected return. Thus, the exposure of an investor to the risk related to firm-specific events (unsystematic risk) can be eliminated by holding a well-diversified portfolio. Systematic risk, on the other hand, cannot be diversified away in a portfolio context.

Since unsystematic risk can be eliminated in a well-diversified portfolio, according to CAPM theory investors need only concern themselves with the degree of systematic risk possessed by an asset. Beta is a measure of the systematic risk of an asset. The level of beta of an asset indicates the risk contribution of that asset to the overall risk of a well-diversified portfolio. The higher the expected risk (*i.e.*, beta) of an investment in an individual asset, the higher the risk contribution of that asset to the risk of a portfolio and, thus, the higher will be the return that an investor would require to be willing to make such an investment.

The beta value of all assets, on average, is equal to 1.0. If a particular asset has a beta of 1.0, this means that the variability in its returns resulting from macroeconomic events will be equal to, and in phase with, the variability of returns in the economy as a whole. An asset with a beta of, say, .5 is only half as responsive to economy-wide events as the market index. When the market index goes up 10 percent, the price of this stock will only go up 5 percent. If the market index declines 30 percent, the price of this investment will only decline 15 percent. An asset with a beta of 2.0 has twice the volatility of the market index. If the market index goes up 20 percent, the price of this asset will go up 40 percent. If the market index declines 5 percent, the price of this asset will decline 10 percent.

Under CAPM theory, the basic formula that can be used to determine the market-required rate of return for a company is:

$$R_i = R_f + b_i \, [E(RP)]$$

where:

R_i	=	required return on security i
R_f	=	current return on risk-free investments
b_i	=	beta for security i
E(RP)	=	expected market risk premium, *i.e.*, the expected difference between the return in the market and the rate of return on a risk-free investment

In the above formulation, the required rate of return for a company is equal to the current return on a risk-free investment plus the product of that company's beta times the expected market risk premium. The market risk premium is that extra return that investors require for an investment in assets of the market as a whole as compared with the return on a risk-free investment.

Q. What data requirements are necessary to implement the CAPM approach?

A. In order to use the CAPM approach for the comparison companies, three parameters must be estimated—beta, the current risk-free rate and the expected market risk premium.

Q. How do you determine beta for the CAPM calculation?

A. The average beta of the comparison companies is 0.60, per *The Value Line Investment Survey*, March 22, 2002. I will employ a beta of 0.60 in the CAPM calculation.

Q. How do you determine the current risk-free rate of return?

A. Since we are trying to determine the cost of common equity capital for the comparison companies and equity capital is a long-term investment, it is my belief that the yield on long-term government bonds best reflects the risk-free rate in this context.

Common stock is a long-term investment—it has no maturity date.[5] In this context, it is interesting to note that the DCF approach determines the cost of equity in terms of a long horizon—*i.e.*, dividends are discounted to infinity in the DCF calculation. Even if an investor sells his or her common stock after only a few years, the successor investor determines the price that the original investor can receive, and so on. Based on the above, equity capital should be considered as a long-term investment and, therefore, the yield on long-term Government bonds best reflects the risk-free rate in this context.

[5] The common stock of a utility will remain outstanding unless a company merges or becomes defunct, or if an investor voluntarily sells his shares back to the company.

Under a long-term investment horizon, if one purchased, say, three-month Treasury securities and then kept rolling over the proceeds each three months as the investment matures, there would be substantial uncertainty (risk) as to what return one would earn over a long horizon by just investing in three-month Treasury bills. In contrast, in the context of a long horizon, if a long-term Treasury bond is held until maturity, then there is no uncertainty as to the expected return—the interest payments and principal are guaranteed in nominal terms. Thus, using a long-term Government bond more closely matches the long-term investment horizon of equity and is therefore appropriate to use in a CAPM analysis for estimating the cost of equity.

I note that short-term Treasury securities are used by the Federal Reserve to implement its policy objectives for credit tightening and expansion. Thus, short-term Treasury security yields are greatly influenced by short-term Federal Reserve policy moves. These short-term adjustments should not be used to measure the long-term risk and return evaluations of investors for common stock.

The average yields on long-term Treasury securities over the October 2001-March 2002 period,[6] per the *Federal Reserve Statistical Release*, were as follows:

[6] This is the same period I employed to obtain prices for my DCF analysis.

	Average Yield
10-Year	4.92 %
20-Year	5.61
Long-Term *	5.47

**The Federal Reserve Statistical Release* reported the yield on 30-year Treasury bonds through January 2002, after which point the series was discontinued and a new series of long-term Treasury bond yields (with at least 25 years or more remaining until maturity) was commenced starting in February 2002.

Recent long-term Treasury bond futures yields have been close to 6.10 percent. Based on all the above-described data, I believe it would be appropriate to use a risk-free rate of 5.55 percent in the CAPM calculation.

Q. How do you determine the expected market risk premium?

A. For the third parameter needed for the CAPM approach, we must estimate the <u>expected</u> market risk premium—*i.e.*, the expected difference between the market-required return on common stocks and the yield on long-term government bonds.

Expectational risk premium data are not directly observable in the marketplace. Therefore, to estimate the expected market risk premium, I follow two approaches. The first approach employs historic long-term risk premium data from Ibbotson Associates *Risk Premia Over Time Report: 2002*. In the second approach, I calculate a cost of equity estimate for the market, in general, using a DCF approach and then subtract the estimate of the risk-free rate from this figure in order to determine the expected market risk premium.

Q. Will you now describe how you will use historic data from the Ibbotson publication to estimate the expected market risk premium?

A. As I indicated earlier, expectational risk premium data are not directly observable in the marketplace. Therefore, one can use estimates of historic realized return spreads as proxies for expected risk premiums. This approach is reasonable since it is plausible to assume that investors use the historic experience as a guide when forming their expectations of risk premiums in the future.

Ibbotson Associates publishes the *Risk Premia Over Time Report: 2002* in which the returns on common stocks and long-term government bonds are reported for the 1926-2001 period. Based on these data, the spread between common stock returns and returns on long-term government bonds has been 7.4 percentage points on an historical basis. I will use this 7.4 percent figure as the expected market risk premium in this CAPM analysis.

In the above discussion, I have employed figures reflecting the arithmetic mean rather than the geometric mean of the data. I believe that a rational investor would employ the arithmetic mean and would not use the geometric mean, because that would provide an understatement of expected future return. (I note that Ibbotson Associates states that the arithmetic mean is the correct measure to use in estimating the cost of equity capital.) Since the explanation of why the arithmetic mean should be used is quite lengthy, I have included it in Exhibit RGR-5 to this testimony. Exhibit RGR-5 shows that the arithmetic mean is the appropriate figure to use when investors are making forecasts about the future and dealing with uncertainties inherent in making projections.

A simple example also shows that the arithmetic mean is the correct approach to use in this context. Let us assume that you are faced with the prospect of betting on a coin toss where you win 50 percent of your bet if the coin comes up heads, but lose 50 percent of the bet if the coin comes up tails.[7] Common sense indicates that because the coin is a fair coin (*i.e.*, a 50 percent chance of landing on heads and a 50 percent chance of landing on tails), bettors would expect to only break even (*i.e.*, they would expect to lose 50 percent of their bet half the time and expect to win 50 percent of their bet half the time). The arithmetic average of the return prospects a bettor would face in these circumstances is zero. Thus, the common sense expectation of a bettor in this example reflects the arithmetic average of return possibilities. In sharp contrast, the geometric average of an equal prospect of two returns (one plus 50 percent and one minus 50 percent) is -13.4 percent. Rational bettors would not go into a coin toss of the type described above with the expectation of a loss of 13.4 percent over time—they would expect to break even, as reflected in the arithmetic mean of zero. Clearly, they would <u>not</u> use a geometric average of return possibilities as their expected value, but would, instead, use the arithmetic average.

Q. Can you explain why it is reasonable to assume that investors look at achieved return spread results of the past in formulating their risk premium expectations for the future?

A. As noted above, I examined historical return spread data over the 1926-2001 period and the results represent 76 years of return experience. The data that I examined,

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[7] Implicit in this discussion is an assumption that the coin used is fair—it is not biased (*e.g.*, weighted) to land disproportionately on either heads or tails.

which represents the experience of a large number of companies over a lengthy period of time, indicates what return spreads investors have actually achieved, on average, in the past. It is not unreasonable to assume that, given the very extensive return spread experience examined, that investors would use this historic experience in formulating their expected risk premium for the future. Put simply, they see what return spread has been achieved in the past and use that experience as an expectation of what might be achieved in the future. Because of this consideration, I believe that the average historic return spread is appropriate to use as the expected risk premium in a CAPM analysis.

The 2002 Ibbotson *Yearbook* states that:

> A proper estimate of the equity risk premium requires a data series long enough to give a reliable average without being unduly influenced by very good and very poor short-term returns.... Some analysts estimate the expected equity risk premium using a shorter, more recent time period on the basis that recent events are more likely to be repeated in the near future; furthermore, they believe that the 1920s, 1930s, and 1940s contain too many unusual events. This view is suspect because all periods contain "unusual" events. Some of the most unusual events of this century took place quite recently, including the inflation of the late 1970s and early 1980s, the October 1987 stock market crash, the collapse of the high-yield bond market, the major contraction and consolidation of the thrift industry, the collapse of the Soviet Union, and the development of the European Economic Community—all of these happened in the last 20 years.... The 76-year period starting with 1926 is representative of what can happen: it includes high and low returns, volatile and quiet markets, war and peace, inflation and deflation, and prosperity and depression. Restricting attention to a shorter historical period underestimates the amount of change that could occur in a long future

> period. Finally, because historical event-types (not specific events) tend to repeat themselves, long-run capital market return studies can reveal a great deal about the future. Investors probably expect "unusual" events to occur from time to time, and their return expectations reflect this.

I agree with the sentiments expressed above and think it is appropriate to assume that investors would use the full range of experience available to them.

It should be noted that in individual years in the period under study, realized return spreads fluctuated significantly and even were negative in some cases. However, the <u>expected</u> risk premium of investors in each year must be positive; if not, a rational investor would never be willing to purchase a risky asset. One must always keep in mind that the risk premium concept is expectational. While investor ex ante risk premium expectations will not be matched in every year by the achieved ex post return spreads, investors will look at the average achieved return spread over a long period to get a sense of what would be realistic to expect for the future. The realized return spreads that I analyzed reflect a body of historic experience based on which investors would reasonably form their return expectations for the future. Of course, it is those future expectations that we are trying to ascertain. Atypically high or low results in any given historic period are not indicative of investors' expectations. Moreover, a negative return spread in any particular historic year or period does not cause investors to expect that in the future they will only be able to achieve negative return premiums, on average. It is, therefore, my view that the average realized return spread over a long period is likely to be viewed by investors as a reasonable estimate of the expected risk premium.

Q. How do you specifically implement the CAPM approach for the comparison companies using the Ibbotson market risk premium?

A. The beta for the comparison companies, per Value Line, is 0.60. The expected market risk premium is 7.4 percent. The risk-free rate is 5.55 percent. Using these inputs, the average required return for the comparison companies is calculated below:

$$R_i = 5.55 + 0.60(7.4) = 10.0\%$$

Thus, using the Ibbotson risk premium in the CAPM method, I find that the average cost of equity for the comparison companies is 10.0 percent.

Q. Will you now describe how you use S&P 500 data to estimate the expected market risk premium?

A. I first calculate an estimate of the expected (required) return for the S&P 500 using the DCF method and then subtract the risk-free rate employed in my analysis in order to determine the expected market risk premium under this second approach.

The dividend yield for the S&P 500 over the six months ending March 2002 has been about at the 1.5 percent level. According to IBES and the S&P Earnings Guide, projected earnings growth for the companies they cover averages 14.7 percent or more. Using 14.7 percent as a conservative estimate of expected growth and a 1.5 percent dividend yield, the DCF estimate of the expected return for the S&P 500 is 16.2 percent (1.5 + 14.7 = 16.2). Using a risk-free rate of 5.55 percent, the expected market risk premium would be 10.6 percent (16.2 – 5.55 = 10.6). Employing this expected market risk premium for the S&P 500, the average required return for the comparison companies is calculated below:

$$R_i = 5.55 + 0.60(10.6) = 11.9\%$$

Q. Would you summarize the CAPM calculations you have performed thus far?

A. The CAPM cost of equity estimate using Ibbotson data was 10.0 percent, while the CAPM estimate based on S&P data was 11.9 percent.

Q. Are there any other factors to consider that may not be captured by the CAPM calculations described above?

A. Yes, there are. Ibbotson Associates indicates that companies with market capitalization in the mid-, small- or micro-capitalization range (including many utilities) require higher returns than indicated by the CAPM formulation I have employed above. As a way to account for this phenomenon, a size premium can be added to the CAPM results.

According to the Ibbotson Associates *Risk Premium Over Time Report: 2002*, size premiums of 70, 140 and 330 basis points are appropriate for mid-, small- and micro-capitalization companies, respectively. I will use a 100 basis point size premium for the comparison group to recognize that four of the companies (AGL, Nicor, Peoples and WGL) are in the mid-capitalization range, four of the companies (Atmos, Laclede, Piedmont and Southwest) are in the small-capitalization range and one company (Cascade) is in the micro-capitalization range. Thus, the CAPM cost of equity estimates are 10.0 and 11.9 percent not including the size premium and 11.0 and 12.9 percent including the size premium. Based on these results, in my further calculations, I will use a range of 11.0-12.0 percent as the CAPM cost of equity estimate.

E. Risk Premium Analysis

Q. Would you provide an overview of your risk premium calculations?

A. I employ two risk premium approaches. The first analysis is based on the historic average spread between utility stocks and bonds. The second relies on a regression analysis to measure how utility risk premiums vary with the level of interest rates.

Q. Will you explain the rationale behind a risk premium analysis?

A. The higher the perceived risk of an investment, the higher will be the return that investors require from that investment. If two investments offer the same expected return but have differing risks, investors will prefer the investment with lesser risk. Investors do so because they are said to be risk averse—*i.e.*, they prefer to take on less risk, rather than more risk, other things being equal.

It is nearly universally agreed that investors require a higher rate of return for an investment in the common equity for a particular company than they do in its debt. This is so for two important reasons. First, if an enterprise fails, debtholders have priority over equityholders as to the remaining assets of the company. Second, for an ongoing business, debtholders must be paid their contractual level of interest before equityholders can receive anything. Because of this basic fact of financial life, companies may reduce their dividend payments to equityholders when under some financial strain. The cessation of payments to debtholders is a much rarer occurrence and will usually result in bankruptcy, unless corrected. In summary, debt is thought to be less risky than equity because debtholders have priority over equityholders as to: (1) distribution of assets in the case of dissolution of the company and (2) distribution of earnings in the case of everyday operations. Because equityholders "take second," they require a higher return than do debtholders. In order to be induced to choose a higher risk investment, an investor would have to be offered an expectation of some increment in return—a premium for incurring additional risk. This incremental return is often known as the "risk premium" and it reflects the additional return that investors require to invest in common equity rather than debt.

The cost of equity is not directly observable, but must be estimated using inferences and judgment. In contrast, a bond yield is observable and if we know, or can estimate, the risk premium that common equity investors require to invest in common equity rather than debt, we can employ the risk premium approach to estimate the cost of common equity. In the well-known Hope decision, the U.S. Supreme Court said:

> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. [320 U.S. 591 at 603.]

While this decision speaks in terms of returns commensurate with those being earned on investments of comparable risk, implicitly a company must also earn a return far enough above investments of lesser risk in order to be able to attract capital. Thus, if we apply the risk premium approach correctly, we will ensure that the subject company is allowed a high enough return on its common equity, compared with investments of lesser risk, so as to be able to attract capital and to meet the standards laid down by the Hope decision.

In general, the equity risk premium can be expressed in the following manner:

$$RP = K_e - K_d$$

The above equation implies that the equity risk premium is equal to the required return on equity (K_e) minus the required return on debt (K_d).

Q. Would you please describe your first risk premium analysis?

A. To measure the expected risk premium between utility common stock and utility bonds, I use the average return spread actually achieved by investors in these instruments in the past. Between 1954 and 2001, Moody's gas distribution common stock index achieved a market return of 12.09 percent, on average. (The market return in any given year was calculated by summing the dividend paid during that year and the year-end market price and dividing that sum by the beginning-of-year market price.) Over that same period, the average of Moody's utility composite bond yields was 8.12 percent. Thus, the historically achieved spread between gas distribution stock returns and utility bond yields was 3.98

percent (12.09 - 8.12 = 3.98).[8] If we add this average spread to the recent level of bond yields, we can obtain an estimate of the return on utility common stocks that investors are currently expecting/requiring.

Over the six-month period ending March 2002, the average bond yield for Moody's A rated utility bonds was 7.67.[9] Adding this recent average bond yield to the historic average spread between gas distribution common stock returns and utility bond yields of 3.98 percent, we obtain a cost of equity estimate for the proxy group of 11.65 percent.

Q. In your second risk premium analysis, is there a proxy for required returns on equity that you use?

A. Yes, there is—returns on common equity allowed to gas distribution utilities by regulation. Most regulatory commissions frequently refer to movements in, or the level of, interest rates in their decisions establishing an allowed return on equity. Since authorized returns appear to be interest-rate sensitive, employing allowed returns from across the United States in calculating the risk premium serves to use outside, objective evidence as to what the consensus of regulation believes is the spread between the cost of equity and bond yields.

Q. How specifically did you perform your second risk premium analysis?

A. I first conducted an analysis of risk premiums implied by allowed returns on equity since 1980. Specifically, quarterly average allowed returns for the first quarter 1980 through the first quarter 2002 were obtained from data in Regulatory

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8 Figures do not add exactly due to rounding.
9 The companies in my proxy group had a median bond rating of A.

Research Associates *Regulatory Focus*. These data reflect the average of allowed returns for all gas distribution utility cases decided in the quarter specified. An implied risk premium (which can also be thought of as an allowed return spread) was derived by comparing the average allowed return in a given quarter with the average yield for Moody's Utility Composite Bond Index in the two quarters prior to the average allowed return.

In deriving the implied risk premium, the utility bond yields were lagged behind the allowed returns on equity because of the likelihood that changes in allowed returns on equity often lag somewhat behind changes in bond yields. This could be so for two reasons—one economic and one practical. The economic reason is that commissions might want to be convinced that a change in interest rates actually represented a trend that might persist before reflecting such change in the allowed return on equity. The practical reason simply deals with the logistics of a rate case—the record that a commission examines may be several months old by the time it renders a decision. (While certain commissions update record data in their decisions, many commissions do not do so.) Furthermore, the simple logistics of writing a decision may cause a delay between the period upon which the allowed return was based and the date on which the decision was released to the public.

To determine the sensitivity of the implied risk premiums described above to the level of interest rates, a regression analysis was conducted. In this regression, the implied risk premium described above was the dependent variable and the level of interest rates, as proxied by the yield on long-term Treasury bonds lagged two quarters behind the allowed return on equity, was the independent variable. This model attempts to capture the statistical relationship between implied risk premiums (*i.e.*, allowed returns minus utility bond yields) and the level of interest rates (as indicated by the yields on long-term Treasury bonds), with the interest rates being lagged two quarters behind the allowed return on equity. The regression equation is reported below:

$$\text{Risk Premium} \quad = \quad 6.496 - 0.448 \left\{ \begin{matrix} \textit{Yield on Long-Term} \\ \textit{Treasury} \\ \textit{Bonds} \end{matrix} \right\}$$

The adjusted R^2 of the regression (which measures the proportion of variation in the dependent variable explained by variation in the independent variable) is 0.79. Thus, this regression relationship demonstrates that changes in the level of interest rates explain a substantial proportion of the changes in implied risk premiums.

One might well ask why one should go through the process of creating the model described above when one could merely just examine recent levels of allowed returns. There are justifications for the model in this context. First, it is possible that in certain quarters there are an insufficient number of allowed returns to use as a guide by themselves. Second, allowed returns are not a perfect proxy for required returns and the use of the long-term relationship between allowed returns and bond yields allows us to overcome any unusual allowed return results in a particular period.

The average yield on long-term Treasury bonds for the six months ending March 2002 is 5.47 percent. Inserting this into the model shown above, I obtain a calculated risk premium of 4.05 percent as follows:

$$\text{Risk Premium} = 6.496 - 0.448(5.47)$$

$$\text{Risk Premium} = 4.05\%$$

The average yield on Moody's A rated utility bonds in the six months ending March 2002 was 7.67 percent. Adding the yield of 7.67 percent to the risk premium derived above of 4.05 percent produces an implied cost of equity of 11.72 percent. Thus, my second risk premium cost of equity estimate for the proxy group of utilities is 11.72 percent according to the above-described analysis.

Q. Would you summarize the results of your risk premium analyses?

A. The first risk premium approach that employs the historic average spread between gas distribution utility common stock returns and utility bond yields produced a cost of equity estimate for the proxy group of 11.65 percent. The second risk premium approach which is based on a regression analysis measuring how utility risk premiums change as the level of interest rates change produced a cost of equity estimate of 11.72 percent for the proxy group.

F. Comparable Earnings Analysis

Q. Can you explain why the comparable earnings approach is helpful in assessing what return should be allowed in this proceeding?

A. The basic criteria for determining what constitutes a fair rate of return for a regulated enterprise were set forth by the U.S. Supreme Court in the Bluefield and Hope cases. In the Bluefield case the Court said:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that

> generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. [262 U.S. 679 at 692-693.]

In Hope, the Court said:

> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses, but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. [320 U.S. 591 at 603.]

In those decisions, the Court enumerated a two-part standard for a fair rate of return: (1) a fair rate of return to a regulated company is one that is equal to that earned in other enterprises of similar risk and (2) the fair rate of return must also provide enough earnings to enable the company to maintain its credit standing and to attract capital. The first part has come to be known as the "comparable earnings standard" while the second part is referred to as "the capital attraction standard."

The comparable earnings approach (*i.e.*, determining the return earned by companies of similar risk) directly meets one of the basic criteria set forth by the Supreme Court in the Bluefield and Hope decisions. But, in addition, the Court set forth the criterion that the rate of return on equity should also be sufficient for the company to attract capital. It must be acknowledged that a firm whose return is the same as that of "other enterprises having corresponding risks" is not necessarily earning enough to attract capital; but in reasonably prosperous periods, one can expect that the great majority of companies are earning enough to attract capital, and that one can also identify those that are not. Thus, if comparisons are made with a reasonably broad range of companies over a reasonably representative time period, one can be confident that a return high enough to match that of other enterprises with corresponding risks will probably also be high enough to attract capital and maintain financial integrity.

In addition to being prescribed as a standard by the Bluefield and Hope decisions, there are other reasons why a comparable earnings analysis may be helpful in determining the return to be allowed a regulated company. The comparable earnings method analyzes the question of what return should be allowed a regulated company from a different perspective from an approach such as the DCF method. It can be argued that the price that investors pay in the stock market for a utility depends, at least in part, on the return that investors expect a commission will allow that company. In turn, however, the return that a commission will allow a company depends, at least in part, on the price of that company in the stock market. As one commentator has stated:

> Moreover, since the most important risk to the investor is the risk as to the attitude of the regulatory commission, current security prices inevitably reflect projections not only of future physical and general economic developments of the utility and its area, but also of the anticipated rulings of the commission. For the commission to "rely" on such anticipations is palpably circular reasoning.... Commissions and

> investors cannot sensibly continue to look behind one another like endless images in multiple mirrors.[10]

Thus there is an element of circularity in using an approach such as the DCF method to estimate the cost of equity of a utility. The comparable earnings method, which derives its results from a conceptually different approach, can shed additional light on the question of the appropriate allowed return for a utility.

Another advantage of a comparable earnings analysis is that it provides a perspective different from that implicitly employed using an approach that satisfies the capital attraction standard. If the capital attraction standard is strictly and rigidly applied, it would keep a company on the knife-edge of financial health—any shortfall in return might make it difficult for a company to attract capital. As another commentator has stated:

> It should be evident that a rate of return which is barely adequate to allow for the raising of new capital is not necessarily a fair rate of return.[11]

The comparable earnings approach is not a market-based methodology. However, the examination of returns earned, or expected to be earned, by a large group of companies with risks similar to gas distribution utilities, in combination with the results of various other methodologies, will produce a reasonable estimate of the return to be allowed for gas distribution utilities.

Q. Would you now describe the comparable earnings analysis you conducted?

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[10] Harold Leventhal, "Vitality of the Comparable Earnings Standard for Regulation of Utilities in a Growth Economy," *The Yale Law Journal*, May 1965, page 1007.

[11] Herman Roseman, "Comparable Earnings and the Fair Rate of Return," 1970 *Annual Report*, Section of Public Utility Law of the American Bar Association, page 26.

A. Under the comparable earnings approach, I first evaluate the risk of the comparison companies versus that of companies in the U.S. economy in general and based on this analysis determine what return on equity is appropriate.

Q. How do you evaluate the relative risk of the comparison companies versus companies in general?

A. I use the Value Line Safety Rank. *The Value Line Investment Survey* provides a safety rank for the 1700 or so companies that it follows. For the determination of Safety Rank, stocks are ranked from 1 to 5, with 1 being the safest and 5 being the most risky. Value Line defines the Safety Rank as a measure of the total risk of a stock and describes the Safety Rank as one of the main criteria investors should consider in selecting stocks. Value Line derives the Safety Rank by averaging two variables: (1) the volatility of the stock as measured by its Index of Price Stability and (2) the Financial Strength Rating as determined by Value Line analysts. Value Line defines the price stability index as being based upon a ranking of the standard deviation of weekly percent changes in price of a stock over the last five years. Value Line evaluates the Financial Strength of a company on a scale of A++ down to C. This is a relative ranking comparing the subject company's financial strength with all other companies. The rating is based upon financial leverage, business risk, company size and the judgment of Value Line analysts. The analysts examine various ratios such as coverage, return variability, accounting methods and size.

To implement the comparable earnings analysis, I examined recent earned and projected returns on shareholders' equity earned by companies with a safety factor of 2 as reported in *The Value Line Investment Survey.*[12]

Q. Does this group of companies with the Safety Rank of 2 include unregulated companies?

A. Yes, it does. It is a financial fact of life for a utility company that it competes in the marketplace to obtain capital not only with other utilities, but with all economic enterprises. Furthermore, the Hope decision, which is a touchstone in the area of rate of return regulation, indicated that a company should be compared with other firms of comparable risk and did not limit this comparison only to other regulated firms. Value Line measures the risk embodied in the safety rank it assigns consistently across the 1700 or so companies that it follows to derive its safety rank and thus it measures risk in a uniform manner for both regulated and unregulated firms.

Q. What returns are companies with a Safety Rank of 2 earning?

A. The earned return on shareholders' equity in any one given year is not necessarily the return that investors expect a firm to earn in the future. A company could have runs of good luck or bad luck or particular accounting adjustments so that the return earned in any one year is not necessarily a meaningful indicator of what it ought to be earning in light of the risks being borne. In order to temper the earned return data, I examined earned returns on shareholders' equity over three recent

[12] The proxy group of utilities I employ in the cost of equity analyses described above has a median Value Line Safety Rank of 2.

historic years. In addition, Value Line projected earned returns for the current year (2002) and for a period 3-5 years into the future were also employed. Thus, by looking at both the earnings experience of the recent past as well as projections for the future, unusual figures are smoothed and the end result is appropriate to employ as the comparable earnings result. To further temper the data, median results, rather than average figures, were used in any year.

The median returns on shareholders' equity in 1999, 2000 and 2001 for companies accorded by Value Line a safety factor of 2 are 14.7, 15.3 and 13.5 percent, respectively. The median projected return on shareholders' equity for these companies in 2002 is 13.5 percent. The median return for these companies projected by Value Line for the near-term future (2004-2006) is 15.0 percent.

In summary, a conservative estimate[13] of the return to be allowed on common equity using the comparable earnings approach is in the range of 13.5-15.0 percent.

G. Determination of the Cost of Equity

Q. Would you describe the results of each of the four methods?

A. The DCF method produced a cost of equity range of 11.25-11.50 percent. As I indicated in my testimony, given that stock prices currently are being affected by a

[13] The data that I examined reflect the return earned on shareholders' equity, rather than the return on common equity. Since the companies examined are financed in part by some preferred equity in addition to common equity, the returns on common equity would be higher than those reported. In addition, Value Line reports return on year-end shareholders' equity, whereas it is appropriate to use return on average equity for the comparable earnings analysis.

complex set of phenomena, including a changing assessment of utility risk, I believe that a utility DCF estimate will have the potential for more measurement error than during periods in which a company's more-readily-determined future earnings and dividends prospects were the main consideration. Therefore, I believe that it is important to also consider the results of the other methods that I presented, which approach the determination of the return on equity to be allowed in this proceeding from different perspectives.

The CAPM approach can be thought of as calculating a risk premium for the market as a whole and then adjusting it for the risk of the particular utility in question. Under the CAPM approach, risk is measured by a company's beta. My CAPM analysis produced a cost of equity range of 11.0-12.0 percent.

While the CAPM approach calculates a market-wide risk premium that is then adjusted for company-specific risk, the two risk premium analyses that I performed directly estimate the risk premium for a utility. The results of these risk premium analyses produced a cost of equity figure in the range of 11.65-11.70 percent.

The comparable earnings approach (*i.e.*, determining the return earned by companies of similar risk) directly meets one of the basic criteria set forth by the Supreme Court in the Bluefield and Hope decisions. As utilities face a more competitive environment, investors will carefully evaluate how utility returns compare with those of unregulated enterprises. The comparable earnings analysis produced a return on equity[14] range of 13.5-15.0 percent. These expected returns on equity of comparable-risk investment alternatives would certainly be taken into account by investors in forming their return requirements for a utility. As discussed above, it is difficult to ascertain with clarity at the current time what the prospects of the utility industry will be in the future. However, the use of rates of return of companies of comparable risk across a diversity of industries provides an important benchmark as to the return to be allowed in this proceeding.

Q. Based on your discussion and analyses, what return do you recommend for the Company?

A. Below, I present a summary of the results I discussed above:

Cost of Equity Method	Range
1. DCF	11.25-11.50%
2. CAPM	11.0-12.0
3. Risk Premium	11.65-11.70
4. Comparable Earnings	13.5-15.0

Determination of the cost of equity requires inferences regarding investor expectations and requirements, which are not directly observable. Each of the above methods approaches the estimation of the cost of equity from a different

[14] As indicated above, the reported range reflects returns on year-end shareholders equity (including preferred equity); returns on average common equity would be somewhat higher.

perspective—which I believe to be a strength of this four-method approach. I recommend a return on equity for the Company in this proceeding in the range of 11.0-12.0 percent. This range is close to the central tendency of the first three cost of equity estimates but is below the comparable earnings result. As I indicate below, I will use the lower end (11.0 percent) of the range to derive the overall cost of capital for AGD.

III. ESTIMATION OF THE OVERALL COST OF CAPITAL

Q. Having determined the cost of common equity for AGD, would you provide an overview of how you will determine the overall cost of capital?

A. I will first determine an appropriate capital structure. Then, I will calculate the cost of debt. Finally, I will develop an overall cost of capital recommendation.

Q. Is it appropriate to use the capital structure of Citizens as the capital structure for AGD in this proceeding?

A. No, it is not. As I noted above, Citizens is primarily a telecommunications company at the current time, with gas operations only accounting for about 17 percent of total revenues. Furthermore, Citizens has announced a policy wherein it is attempting to sell the regulated gas utility operations in the near future. Citizens, because it has taken on substantial debt in acquiring telecommunications businesses, is projected by Value Line to have a common equity ratio of only about 26 percent at the end of 2002—a level well below that of typical gas distribution utilities.[15] This Commission has recognized the propriety of using a hypothetical capital structure. The Commission, at page 34 of its August 12, 1993 Decision No. 58377 concerning Southwest Gas, stated that:

> The Commission prefers to utilize a company's actual capital structure in determining the overall cost of capital. However, the Company's overall capital structure is excessive in debt because of its Bank acquisition and is not necessarily representative of the Company's Arizona-specific utility operations. For that reason, a hypothetical capital structure must be imputed to the Company for ratemaking purposes.

For all of these reasons, I do not believe it would be appropriate to employ the capital structure of Citizens as a proxy for the capital structure of AGD in this proceeding.

Q. How then do you proceed in determining an appropriate capital structure for AGD?

A. In determining an appropriate capital structure, I examine the capital structure of the proxy group of companies I have employed in my cost of equity analysis. On Exhibit RGR-6, I show the proxy group actual capital structure for the Year 2001, as reported by Value Line and Value Line estimates for the projected capital structure for the years 2002, 2003 and 2005-2007. I note that the capital structure data shown on Exhibit RGR-6 show a slight upward trend in the common equity ratio over the periods being examined, moving from a median equity ratio of 50.2 percent in 2001 up to a median projected equity ratio of 54.0 percent in 2005-2007.

Q. What is your recommendation for the appropriate capital structure for AGD in this proceeding?

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[15] In fact, the 26 percent common equity ratio of Citizens is less than half that of a typical telecommunications company, according to Value Line data.

A. Based on the capital structures of the proxy group I have employed in this testimony, I believe it is appropriate to employ a capital structure for AGD in this proceeding consisting of 50 percent debt and 50 percent common equity.[16]

Q. How do you determine the cost rate for debt to use in this capital structure?

A. To determine the cost of long-term debt, I employ the cost rates for my proxy group of companies, as derived from year-end 2001 data reported in *The Value Line Investment Survey.* I have calculated that the median cost rate of long-term debt for the proxy group is 6.7 percent. I will employ this cost rate of debt in order to derive the overall cost of capital for AGD.

Q. What is your recommendation for the overall cost of capital for AGD?

A. My overall cost of capital recommendation for AGD is presented on Exhibit RGR-7. That Exhibit uses inputs that I have derived in the discussion above and reaches an overall cost of capital for AGD of 8.85 percent. In this calculation, at the Company's request, I have employed the lower end (*i.e.*, 11.0 percent) of my cost of equity range as the cost rate for the common equity component of the capital structure.

Q. Does this conclude your testimony?

A. Yes, it does.

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[16] Some of the proxy companies on Exhibit RGR-6 have small amounts of preferred stock. The median preferred stock ratio for the group is (essentially) zero and only three of the nine proxy companies are projected to have any preferred stock in the future. Because of these considerations, I use only debt and common equity in the recommended capital structure.

1

EDUCATION AND EMPLOYMENT BACKGROUND OF ROBERT G. ROSENBERG

Education

I have a Bachelor of Arts degree in Political Science, with a minor in Economics, from Hunter College. I received a Master of Business Administration degree with a major in Finance at the New York University Graduate School of Business Administration.

Employment

From 1969 through mid-March 1983, I was employed by the firm of National Economic Research Associates (NERA), reaching the position of Senior Economic Analyst. In March of 1983, I became a principal of Benrose Economic Consultants, Inc., a consulting firm in New York City. In April 2000, I became a principal of Edgewood Consulting, Inc., a firm located in the Capital District area of New York. Edgewood Consulting performs economic research and consulting services for companies, law firms, government agencies and trade associations. Throughout this period, I have concentrated on the analysis of regulated industries, including electric and gas utilities, insurance and steamship companies. I have prepared direct and rebuttal testimony related to financial aspects of utility rate proceedings--*e.g.*, cost of common equity, capital structure, etc. Along with these "typical" rate case issues, I have also testified regarding more unusual matters: intra-company royalty payments; the correct procedure to use in calculating the cost of debt; whether a cogeneration project met Qualifying Facility ownership standards; and responsibility for stranded costs.

I have had numerous assignments involving evaluation, consultation and/or internal reports to clients. Examples of this include: (1) analyzing issues relating to industry restructuring (*e.g.*, implications of Commission-ordered divestiture, the risks associated with the institution of incentive plans, unbundling electric rates, etc.); (2) consulting with a utility company concerning the financial and regulatory aspects of a potential merger and the possible regulatory treatment of an acquisition premium; (3) evaluating the feasibility of instituting an administrative securitization proposal; (4) determining incremental risks flowing from purchased power contracts; and (5) analyzing studies regarding property values near transmission lines.

Outside the regulatory arena, I have estimated financial damages related to (1) breach of contract and (2) earnings losses as a result of injuries. I have also examined stock prices to see if alleged manipulation was likely and have performed economic valuation for employee stock option plan purposes.

I have presented lectures at the Pace University Center for International Business Studies regarding the regulatory process. Five articles that I authored have been published in *Public Utilities Fortnightly* (PUF).

Appearances Before Regulatory Agencies

I have presented testimony before the Federal Energy Regulatory Commission and the regulatory agencies in the following states: Kentucky, Massachusetts, Minnesota, Mississippi, New Hampshire, New York, Pennsylvania, Rhode Island, South Dakota and Vermont. These testimonies were presented on behalf of: Blackstone Valley Electric Company, Boston Edison Company, Central Hudson Gas & Electric Corporation, Citizens Communications Company, Consolidated Edison Company, Kentucky Utilities Company, Long Island Lighting Company, Louisville Gas and Electric Company, Minnesota Power & Light Company, Mississippi Power Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Northern States Power, Orange & Rockland Utilities, Pacific Gas & Electric Company, Pike County Light & Power Company, Public Service Company of New Hampshire, Public Service Company of New Mexico and Rochester Gas & Electric Corporation. In addition, I have testified before: the Society of Maritime Arbitrators concerning the estimation of damages in the matter of Empresa Publica de Abastecimento de Cereais (an agency of the Government of Portugal) vs. Point Endeavor Corporation and Tradigrain, Inc.; U.S. Bankruptcy Court regarding financing for an office building in Chapter 11; and the Federal Maritime Commission regarding the fair return for Matson Navigation Company.

2

Exhibit RGR-2

COMPARISON GROUP

AGL Resources

Atmos Energy

Cascade Natural Gas

Laclede Group

Nicor

Peoples Energy

Piedmont Natural Gas

Southwest Gas

WGL Holdings

3

CALCULATION OF SIX-MONTH AVERAGE PRICE
October 2001 - March 2002

	Average of Monthly High and Low Price						6-Month Average Price
	October	November	December	January	February	March	
	(2)	(3)	(4)	(5)	(6)	(7)	(8)
AGL Resources	$20.50	$21.37	$22.16	$21.81	$21.87	$22.93	$21.77
Atmos Energy	21.26	20.70	20.58	21.27	21.46	23.32	21.43
Cascade Natural Gas	20.61	21.23	20.95	20.55	19.10	20.33	20.46
Laclede Group	23.95	23.90	23.64	23.70	22.88	23.60	23.61
Nicor	39.52	38.68	40.10	40.73	41.18	43.95	40.69
Peoples Energy	40.32	38.97	37.04	37.25	36.33	38.52	38.07
Piedmont Natural Gas	31.08	32.68	34.60	34.40	32.92	34.13	33.30
Southwest Gas	21.44	21.04	21.83	23.08	23.10	24.18	22.45
WGL Holdings	27.26	27.49	28.38	27.67	26.42	26.93	27.36

Source: MSN Money Central website.

4

DCF COST OF EQUITY CALCULATION FOR THE COMPARISON GROUP

Company	6-Month Average Price	Indicated Dividend	Near-Term Projected EPS Growth: Value Line Projected 5-Year Growth	Near-Term Projected EPS Growth: IBES Projected 5-Year Growth	Near-Term Projected EPS Growth: Average: Value Line and IBES [(3)+(4)]/2	Long-Term Projected Growth in GDP	DCF Cost of Equity Estimate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
AGL Resources	$21.77	$1.08	9.5 %	8 %	8.8 %	6.19 %	12.1 %
Atmos Energy	21.43	1.18	9.0	6	7.5	6.19	12.4
Cascade Natural Gas	20.46	0.96	8.0	5	6.5	6.19	11.2
Laclede Group	23.61	1.34	7.0	3	5.0	6.19	11.9
Nicor	40.69	1.76	8.0	6	7.0	6.19	11.0
Peoples Energy	38.07	2.06	7.5	6	6.8	6.19	12.1
Piedmont Natural Gas	33.30	1.57	6.5	5	5.8	6.19	11.1
Southwest Gas	22.45	0.82	5.0	5	5.0	6.19	9.9
WGL Holdings	27.36	1.26	7.5	4	5.8	6.19	11.0
Median							11.2 %

Source:
- Col. (1) - Exhibit RGR-3.
- Cols. (2)&(3) The Value Line Investment Survey.
- Col. (4) - IBES Monthly Summary Data.
- Col. (6) - Derived from data in Energy Information Administration Annual Energy Outlook, 2002.
- Col. (7) - Derived iteration using an internal rate of return calculation.

DCF COST OF EQUITY CALCULATION FOR THE COMPARISON GROUP

			Near-Term Projected EPS Growth				
Company	6-Month Average Price	Indicated Dividend	Value Line Projected 5-Year Growth	IBES Projected 5-Year Growth	Average: Value Line and IBES [(3)+(4)]/2	Long-Term Projected Retention Growth	DCF Cost of Equity Estimate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
AGL Resources	$21.77	$1.08	9.5 %	8 %	8.8 %	5.5 %	11.5 %
Atmos Energy	21.43	1.18	9.0	6	7.5	5.5	11.8
Cascade Natural Gas	20.46	0.96	8.0	5	6.5	7.5	12.3
Laclede Group	23.61	1.34	7.0	3	5.0	4.5	10.6
Nicor	40.69	1.76	8.0	6	7.0	10.5	14.6
Peoples Energy	38.07	2.06	7.5	6	6.8	6.5	12.3
Piedmont Natural Gas	33.30	1.57	6.5	5	5.8	4.5	9.7
Southwest Gas	22.45	0.82	5.0	5	5.0	4.5	8.4
WGL Holdings	27.36	1.26	7.5	4	5.8	6.0	10.8
Median							11.5 %

Source:	Col. (1)	- Exhibit RGR-3.
	Cols. (2),(3)&(6)	- The Value Line Investment Survey.
	Col. (4)	- IBES Monthly Summary Data.
	Col. (7)	- Derived iteration using an internal rate of return calculation.

DCF COST OF EQUITY CALCULATION FOR THE COMPARISON GROUP

			Near-Term Projected EPS Growth				
Company	6-Month Average Price	Indicated Dividend	Value Line Projected 5-Year Growth	IBES Projected 5-Year Growth	Average: Value Line and IBES (3)+(4)]/2	Long-Term Projected Industry Growth	DCF Cost of Equity Estimate
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
AGL Resources	$21.77	$1.08	9.5 %	8 %	8.8 %	6.5 %	12.3 %
Atmos Energy	21.43	1.18	9.0	6	7.5	6.5	12.6
Cascade Natural Gas	20.46	0.96	8.0	5	6.5	6.5	11.5
Laclede Group	23.61	1.34	7.0	3	5.0	6.5	12.2
Nicor	40.69	1.76	8.0	6	7.0	6.5	11.2
Peoples Energy	38.07	2.06	7.5	6	6.8	6.5	12.3
Piedmont Natural Gas	33.30	1.57	6.5	5	5.8	6.5	11.4
Southwest Gas	22.45	0.82	5.0	5	5.0	6.5	10.1
WGL Holdings	27.36	1.26	7.5	4	5.8	6.5	11.3
Median							11.5 %

Source:
Col. (1) - Exhibit RGR-3.
Cols. (2)&(3) - The Value Line Investment Survey.
Col. (4) - IBES Monthly Summary Data.
Col. (6) - See text.
Col. (7) - Derived iteration using an internal rate of return calculation.

5

WHY THE ARITHMETIC, RATHER THAN THE GEOMETRIC, MEAN SHOULD BE USED IN ESTIMATING EXPECTED FUTURE RETURNS

It has been suggested that in using the Ibbotson historic rate of return data as a proxy for the expected future return, one should employ the geometric mean of the data, rather than the arithmetic mean. I will demonstrate why that contention is incorrect. The only appropriate historic average to use in forecasting expected returns for the future is the arithmetic mean. It is incorrect to use the geometric mean and the use of the geometric mean results in an understated expected future return, as will be demonstrated below.

Before beginning the discussion on this issue, it is perhaps helpful to review the basic definition of the return on an investment that an investor expects (requires). The expected (required) rate of return is the discount rate that equates the future cash flows that an investor expects to receive from an investment with the initial value (*i.e.*, the present value) of that investment. Keeping that basic definition in mind, I will now explain why the arithmetic mean of historic return data is appropriate to use in trying to forecast the expected return in the future.

In examining complicated issues, economists often simplify the actual very complex data or situation of the real world so that the issue in question is more easily examined in the simplified context. I will do so in my discussion below, but note that the principles hold even in the more complex situation of the real world. Let us assume that over a past period, an investment earned a rate of return of either 15 percent or 5 percent, with equal probability. Thus, if we examined an historic period of, say, 100 years, we would expect to find that 50 of those years experienced a 15 percent return, while the remaining 50 years experienced a 5 percent return. Since the two possible returns in this simplified hypothetical example have the same probability, the arithmetic average of these two possible returns would be 10 percent. Having established that the arithmetic average of past returns for the series described is 10 percent, we will now examine whether it is appropriate to use that return as a proxy for expected future returns.

On Page 7, I show a hypothetical example of future possible investment outcomes if we assume that the distribution of possible returns from the past continues on into the future--*i.e.*, that the only two possible returns are 15 percent or 5 percent, each with a 50 percent probability. In Column (1) of Page 7, I show the two possible returns that can be expected to occur in the future, given that these were the only two returns that occurred in the past in our hypothetical example. In Column (2) of Page 7, I show that the initial amount invested is assumed to be \$1.00. In Column (3) I show that at the end of Year 1 an investor could either end up with \$1.15 if the 15 percent return outcome happens or \$1.05 if the 5 percent return possibility happens. Since the \$1.15 outcome and the \$1.05 outcome are equally likely to happen under the hypothesized circumstances, the average possible result (known in financial parlance as the expected value) of this investment at the end of Year 1 is \$1.10--the average of the two possible outcomes that have equal probability. This expected value of the investment of \$1.10 is shown near the bottom of Column (3) of Page 7. If the expected value of this investment at the end of Year 1 is \$1.10 and \$1.00 had been invested in Year 0, then clearly the discount factor that equates the expected cash flow at the end of Year 1, should the security be sold, to the value of the initial investment is 1.10 or 10 percent.

Now let us see what are the possible investment outcomes for Year 2 under the hypothesized circumstances. The possible outcomes are shown in Column (4) of Page 7 and are explained below. If the investment earns \$1.15 in Year 1 and again, fortunately, earns a 15 percent return in Year 2, then the value of the investment would be \$1.3225 at the end of Year 2 (\$1.15 x 1.15 = \$1.3225). Another possible outcome would be if the investment earns \$1.15 in

Year 1 but only earns a 5 percent return in Year 2. This would produce a value at the end of Year 2 of \$1.2075 (\$1.15 x 1.05 = \$1.2075). I will now explain how the third number in Column (4) is derived. If the investment in question earns a 5 percent return in Year 1, but then earns a 15 percent return in Year 2, then the expected value of the investment at the end of Year 2 would be \$1.2075 (\$1.05 x 1.15 = \$1.2075). The fourth possibility in Year 2 is if the investment, unfortunately, only reaches the \$1.05 level at the end of Year 1 and in Year 2 again only experiences a 5 percent return. This would produce the fourth outcome in Column (4), namely \$1.1025 (\$1.05 x 1.05 = \$1.1025).

I have thus explained how one obtains the four possible outcomes at the end of Year 2, as shown in Column (4) of Page 7. Given that each of these outcomes has the same probability (because in any given year there is an equal probability of experiencing either a 15 percent return, or a 5 percent return), if we add up the four possible returns and divide by 4, we obtain the expected value of the investment of \$1.21. Thus, even though there are several possible outcomes in Year 2, the expected value of this investment at the end of Year 2 is \$1.21 under the circumstances hypothesized. If the investor <u>expects</u> to be able to sell the investment at the end of Year 2 with a value of \$1.21, then the discount rate that equates the expected receipt of \$1.21 at the end of Year 2 with the initial investment of \$1.00 in Year 0 is 10 percent ($\$1.21/[(1.10)^2]=\$1.00$). Thus, again, as in Year 1, in Year 2 we find that the discount rate, or expected return, on this investment is 10 percent. This means that if an investor invested \$1.00 in Year 0 and expected the return possibilities shown on Page 7, that the investor would expect to earn a 10 percent return on his or her investment in either Year 1 or in Year 2.

The data shown for Years 3 and 4, in Columns (5) and (6) on Page 7, are derived in a similar manner. I will briefly discuss the data for Year 3 to provide continuity for this explanation. There are eight possible outcomes in Year 3, each with the same probability. Thus, if we sum up the eight possible investment outcomes for Year 3 and divide by 8, we have the average possible outcome or the expected value of the investment at the end of Year 3. As shown in Column (5) on Page 7, the expected value of the investment at the end of Year 3 is \$1.331. Thus, if an investor invested \$1.00 in Year 0 and could expect to sell his investment at the end of Year 3 for \$1.331, the expected return on that investment would be 10 percent. The data shown for Year 4, in Column (6) of Page 7, are derived in a similar manner and again it is indicated that were the investor to sell his investment at the end of Year 4, he would expect to earn a 10 percent return on the investment. This hypothetical example could be extended out further in time, but the calculations would obviously become very cumbersome. The point holds for future years, but the data for Years 1 through 4 will be used for illustrative purposes in the remainder of this discussion.

The hypothetical example shown on Page 7 has demonstrated that under the hypothesized circumstances, in each and every year in the future, investors will expect to earn a return of 10 percent. It is important to note that this 10 percent return that we have calculated that investors could expect in each of the years examined is the same return as the arithmetic average of the two possible return outcomes specified in the hypothetical example, namely 15 percent and 5 percent. Thus, if investors noted that historic return experience was either 5 or 15 percent, with an arithmetic average of 10 percent, and they used this arithmetic average of past returns as a projected return for the future, their projections would exactly match the expected return (or discount rate), derived in the hypothetical example on Page 7. Put simply, this demonstrates that the arithmetic average of past rates of return is the appropriate average to use in forecasting expected future returns, assuming that past conditions will continue on into the future.

Now let us leave the discussion of the arithmetic mean briefly in order to discuss the geometric mean. The geometric mean of two returns is calculated as follows:

$$\sqrt{(1 + r_1) \times (1 + r_2)} - 1$$

where r_1 and r_2 are the two returns in question and are expressed in decimal form.

Given that in the prior hypothetical example the only two possible returns were 15 percent or 5 percent, the geometric average of those returns would be calculated as follows:

$$\sqrt{(1 + .15) \times (1 + .05)} - 1 = .0989 \text{ or } 9.89\%$$

As can be noted above, the geometric mean rate of return for the hypothetical investment we have been discussing is 9.89 percent--less than the 10.00 percent arithmetic mean. From the calculations on Page 7, we have shown that if an investor invested $1.00 at Year 0 in our hypothetical investment, they could expect to have the following values of their investment for each of the years specified:

Initial Investment in Year 0	Expected Value of Investment			
	Year 1	Year 2	Year 3	Year 4
$1.00	$1.10	$1.21	$1.331	$1.4641

As noted previously, these expected values of the investment in each year could also be obtained by taking the arithmetic average of historic results (10 percent) and assuming that the investor expects to earn the arithmetic return in each year in the future.

Now let us assume that an investor mistakenly took the 9.89 percent geometric mean from the historic return series and used that to project the returns earned in the future. If an investor invested $1.00 in Year 0 and expected that he or she would only earn the 9.89 percent geometric mean, then using the geometric mean as a predictor would produce the following data:

Initial Investment in Year 0	Value Produced by Forecasting with Geometric Mean Year 1	Year 2	Year 3	Year 4
$1.00	$1.0989	$1.2076	$1.3270	$1.4582

Note that the values produced above when one uses the geometric mean to forecast future investment outcomes are lower in each and every year than the actual expected value of the investment that was derived on Page 7. This means that the geometric mean will produce an understated prediction of the returns that investors expect in the future. As has been demonstrated throughout this discussion, the arithmetic mean of historic rate of return data produces the rate of return that investors expect in the future, assuming that future conditions parallel that of the past. In contrast, use of the geometric mean to forecast future rates of return based on past results will result in an understatement of the forecasted rate of return for the future.

HYPOTHETICAL EXAMPLE OF FUTURE POSSIBLE INVESTMENT OUTCOMES

Possible Rate of Return	Initial Investment in Year 0	Future Possible Investment Outcome In: Year 1	Year 2	Year 3	Year 4
	----------- Dollars -----------				
					1.7490
				1.5209	
					1.5969
			1.3225		
					1.5969
				1.3886	
					1.4580
15 %		1.15			
					1.5969
				1.3886	
					1.4580
			1.2075		
					1.4581
				1.2679	
					1.3313
	$1.00				
					1.5969
				1.3886	
					1.4580
			1.2075		
					1.4581
				1.2679	
					1.3313
5 %		1.05			
					1.4581
				1.2679	
					1.3313
			1.1025		
					1.3312
				1.1576	
					1.2155
Expected Value of Investment		$1.10	$1.2100	$1.3310	$1.4641
Discount Factor		1.10	$(1.10)^2$	$(1.10)^3$	$(1.10)^4$

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PROXY GROUP CAPITAL STRUCTURE

Company	2001 Long-Term Debt Ratio	2001 Preferred Equity Ratio	2001 Common Equity Ratio	2002 Long-Term Debt Ratio	2002 Preferred Equity Ratio	2002 Common Equity Ratio
	(1)	(2)	(3)	(4)	(5)	(6)
AGL Resources	61.3 %	0.0 %	38.7 %	60.0 %	0.0 %	40.0 %
Atmos Energy	54.3	0.0	45.7	52.0	0.0	48.0
Cascade Natural Gas	50.7	0.0	49.3	56.0	0.0	44.0
Laclede Group	49.6	0.2	50.2	49.5	0.5	50.0
Nicor	37.8	0.5	61.7	36.5	0.5	63.0
Peoples Energy	44.4	0.1	55.5	44.0	0.0	56.0
Piedmont Natural Gas	47.6	0.0	52.4	44.5	0.0	55.5
Southwest Gas	55.7	4.3	40.0	53.0	4.5	42.5
WGL Holdings	41.7	2.0	56.3	45.0	0.0	55.0
Average	49.2 %	0.8 %	50.0 %	48.9 %	0.6 %	50.4 %
Median	49.6 %	0.1 %	50.2 %	49.5 %	0.0 %	50.0 %

Company	2003 Long-Term Debt Ratio	2003 Preferred Equity Ratio	2003 Common Equity Ratio	2005-2007 Long-Term Debt Ratio	2005-2007 Preferred Equity Ratio	2005-2007 Common Equity Ratio
	(7)	(8)	(9)	(10)	(11)	(12)
AGL Resources	57.0 %	0.0 %	43.0 %	55.0 %	0.0 %	45.0 %
Atmos Energy	51.0	0.0	49.0	50.0	0.0	50.0
Cascade Natural Gas	54.0	0.0	46.0	54.0	0.0	46.0
Laclede Group	49.0	0.5	50.5	45.5	0.5	54.0
Nicor	34.5	0.5	65.0	28.0	0.5	71.5
Peoples Energy	39.0	0.0	61.0	30.5	0.0	69.5
Piedmont Natural Gas	42.0	0.0	58.0	37.0	0.0	63.0
Southwest Gas	50.0	4.0	46.0	43.5	3.0	53.5
WGL Holdings	45.0	0.0	55.0	45.0	0.0	55.0
Average	46.8 %	0.6 %	52.6 %	43.2 %	0.4 %	56.4 %
Median	49.0 %	0.0 %	50.5 %	45.0 %	0.0 %	54.0 %

Note: Value Line does not report preferred equity ratios. The preferred equity ratios shown above were derived by subtracting the debt and common equity ratios from 100 percent.

Source: *The Value Line Investment Survey*, March 22, 2002.

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Exhibit RGR-7

OVERALL COST OF CAPITAL FOR AGD

	Percent of Total Capital	Cost Rate	Weighted Cost
Debt	50.0 %	6.7 %	3.35 %
Common Equity	50.0	11.0	5.50
Total	100.0 %		8.85 %

BEFORE THE
ARIZONA CORPORATION COMMISSION
DOCKET NO. G-01032A-02-

DIRECT TESTIMONY OF
DR. RONALD E. WHITE

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Ronald E. White. My business address is 17595 S. Tamiami Trail, Suite 212, Fort Myers, Florida 33908.

Q. WHAT IS YOUR OCCUPATION?

A. I am an Executive Vice President and Senior Consultant of Foster Associates, Inc.

I. QUALIFICATIONS

Q. WOULD YOU BRIEFLY DESCRIBE YOUR EDUCATIONAL TRAINING AND PROFESSIONAL BACKGROUND?

A. I received a B.S. degree (1965) in Engineering Operations and an M.S. degree (1968) and Ph.D. (1977) in Engineering Valuation from Iowa State University. I have taught graduate and undergraduate courses in industrial engineering, engineering economics, and engineering valuation at Iowa State University and previously served on the faculty for Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. I also conduct courses in depreciation and public utility economics for clients of the firm.

I have prepared and presented a number of papers to professional organizations, committees, and conferences and have published several articles on matters relating to depreciation, valuation and economics. I am a past member of the Board of Directors of the Iowa State Regulatory Conference and an affiliate member of the joint American Gas Association (A.G.A.) – Edison Electric Institute (EEI) Depreciation Accounting Committee, where I previously served as chairman of a standing committee on capital recovery and its effect on corporate economics. I am also a member of the American Economic Association, the Financial Management Association, the Midwest Finance Association, the Electric Cooperatives Accounting Association (ECAA), and a founding member of the Society of Depreciation Professionals.

Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?

A. I joined the firm of Foster Associates in 1979, as a specialist in depreciation, the economics of capital investment decisions, and cost of capital studies for ratemaking applications. Prior to joining Foster Associates, I was employed by Northern States Power Company (1968-1979) in various assignments related to finance and treasury activities. As Manager of the Corporate Economics Department, I was responsible for book depreciation studies, studies involving staff assistance from the Corporate Economics Department in evaluating the economics of capital investment decisions, and the development and execution of innovative forms of project financing. As Assistant Treasurer at Northern States, I was responsible for bank relations, cash requirements planning, and short-term borrowings and investments.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have testified in numerous proceedings before administrative and judicial bodies in Alabama, Arizona, California, Colorado, Delaware, Hawaii, Idaho, Illinois, Iowa, Maryland, Massachusetts, Michigan, Minnesota, Missouri, Montana, Nevada, New Hampshire, New Jersey, North Carolina, North Dakota, Ohio, Oregon, Pennsylvania, Rhode Island, South Carolina, South Dakota, Tennessee, Vermont, Wisconsin, and the District of Columbia. I have also testified before the Federal Energy Regulatory Commission, the Federal Power Commission, the Alberta Energy Board, the Ontario Energy Board, and the Securities and Exchange Commission. I have sponsored position statements before the Federal Communication Commission and numerous local franchising authorities in matters relating to the regulation of telephone and cable television. A more detailed description of my professional qualifications is provided in attached Exhibit CCC-REW-1.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Foster Associates was engaged by Citizens Communications Company – Arizona Gas Division (AGD) to conduct depreciation studies for the Northern Arizona Gas Division (NAGD) and the Santa Cruz Gas Division (SCGD) properties. The purpose of my testimony is to sponsor the studies conducted by Foster Associates pursuant to this engagement. Depreciation rates currently used by NAGD were developed in a 1993 study conducted by the Company. Depreciation rates currently used by SCGD were developed in a 1979 study.

Q. A DOCUMENT TITLED 2002 DEPRECIATION RATE STUDY HAS BEEN MARKED FOR IDENTIFICATION AS EXHIBIT CCC-REW-2. WAS THIS DOCUMENT PREPARED BY YOU OR UNDER YOUR SUPERVISION?

A. Yes, it was.

III. DEVELOPMENT OF DEPRECIATION RATES

Q. WOULD YOU PLEASE EXPLAIN WHY DEPRECIATION STUDIES ARE NEEDED FOR ACCOUNTING AND RATEMAKING PURPOSES?

A. The goal or objective of depreciation accounting is to charge to operations a reasonable estimate of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval. A number of depreciation systems have been developed to achieve this objective, most of which employ time as the apportionment base.

Implementation of a time-based or age-life system of depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The average service life of a vintage, for example, is a statistic that will not be known with certainty until all units from the original placement have been retired from service. A vintage average service life, therefore, must be estimated initially and periodically revised as indications of the eventual average service life become more certain. Future net salvage rates and projection curves, which describe the expected distribution of retirements over time, are also estimated parameters of a depreciation system that are subject to future revisions. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The need for periodic depreciation studies is also a derivative of the ratemaking process which establishes prices for utility services based on costs. Absent regulation, deficient or excessive depreciation rates will produce no adverse consequence other than a systematic over or understatement of the accounting measurement of earnings. While a continuance of such practices may not comport with the goals of depreciation accounting, the achievement of capital recovery is not dependent upon either the amount or the timing of depreciation expense for an unregulated firm. In the case of a regulated utility, however, recovery of investor-supplied capital is dependent upon allowed revenues, which are in turn dependent upon approved levels of depreciation expense. Periodic reviews of depreciation rates are, therefore, essential to the achievement of timely capital recovery for a regulated utility.

Q. WHAT ARE THE PRINCIPAL ACTIVITIES INVOLVED IN CONDUCTING A DEPRECIATION STUDY?

A. The first step in conducting a depreciation study is the collection of plant accounting data needed to conduct a statistical analysis of past retirement experience. Data are also collected to permit an analysis of the relationship between retirements and realized gross salvage and removal expense. The data collection phase should include a verification of the accuracy of the plant accounting records and a reconciliation of the assembled data to the official plant records of the company.

The next step in a depreciation study is the estimation of service life statistics from an analysis of past retirement experience. The term *life analysis* is used to describe the activities undertaken in this step to obtain a mathematical description of the forces of retirement acting upon a plant category. The mathematical expressions used to describe these life characteristics are known as survival functions or survivor curves.

Life indications obtained from an analysis of past retirement experience are blended with expectations about the future to obtain an appropriate projection life curve. This step, called *life estimation*, is concerned with predicting the expected remaining life of property units still exposed to the forces of retirement. The amount of weight given to the analysis of historical data will depend upon the extent to which past retirement experience is considered descriptive of the future.

An estimate of the net salvage rate applicable to future retirements is usually obtained from an analysis of the gross salvage and removal expense realized in the past. An analysis of past experience (including an examination of trends over time) provides an appropriate starting point for estimating future salvage and cost of removal. Consideration, however, should be given to events that may cause deviations from the net salvage realized in the past. Among the factors which should be considered are the age of plant retirements; the portion of retirements that will be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to the net salvage observed in the past.

In addition to the estimation of parameters, a comprehensive depreciation study will include an analysis of the adequacy of the recorded depreciation reserve. The purpose of such an analysis is to compare the current balance in the recorded reserve with the balance required to achieve the goals and objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized exactly as predicted. The difference between the required depreciation reserve and the recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to extinguish the reserve imbalance.

Although reserve records are typically maintained by various account classifications, the total reserve for a company is the most important measure of the status of the company's depreciation practices and procedures. Differences between the theoretical reserve and the recorded reserve will arise as a normal occurrence when service lives, dispersion patterns and salvage estimates are changed in the course of depreciation reviews. Differences will also arise due to plant accounting activity such as transfers and adjustments, which require an identification of reserves at a different level than that maintained in the accounting system. It is appropriate, therefore, and consistent with group depreciation theory, to periodically redistribute the total recorded reserve to the various primary accounts on the basis of the most recent estimates of retirement dispersion and salvage. A redistribution of the recorded reserve will provide an initial reserve amount for each primary account consistent with the estimates of retirement dispersion selected to describe mortality characteristics of the accounts and establish a baseline against which future comparisons can be made.

Finally, the parameters obtained from service life and net salvage studies are integrated into an appropriate formulation of an accrual rate based upon a selected depreciation system. Three elements are needed to describe a depreciation system. These elements (*i.e.*, method, procedure and technique) can be visualized as three dimensions of a cube in which each face describes a variety of sub-elements that can be combined to form a system. A depreciation system is therefore formed by selecting a sub-element from each face such that the system contains one method, one procedure and one technique. The sub-elements most widely used in constructing a depreciation system are shown in Table 1.

METHODS	PROCEDURES	TECHNIQUES
Retirement	Total Company	Whole-Life
Compound-Interest	Broad Group	Remaining-Life
Sinking-Fund	Vintage Group	Probable-Life
Straight-Line	Equal-Life Group	
Declining Balance	Unit Summation	
Sum-of-Years'-Digits	Item	
Expensing		
Unit-of-Production		
Net Revenue		

TABLE 1. ELEMENTS OF A DEPRECIATION SYSTEM

Q. DID AGD PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR CONDUCTING THE 2002 DEPRECIATION STUDY?

A. Yes, they did. Foster Associates was provided a transaction database for NAGD originally compiled by the Company and used in its 1993 study. The database had been assembled from a Southern Union Gas Company legacy system that included activity year transactions from inception through December 31, 1991. The database provided aged transactions for all plant accounts with the exception of Account 381.00 (Meters) and Account 383.00 (House Regulators), which were unaged. Foster Associates appended 1992-2001 actual aged transactions to this database and initiated aged transaction activity for the Meters and House Regulator accounts beginning in 1992. The 1992-1998 transactions were compiled from annual "CPR Plant Control" reports issued from a Computer Associates plant accounting system. The 1999-2001 transactions were compiled from the current SAP system installed in 1999 and populated with age distributions at December 31, 1998. Foster Associates reconciled the 1992-2001 activity year total transactions to Company ledger reports and the age distribution of surviving plant was reconciled to the CPR age distribution at December 31, 2001.

Foster Associates was also provided an unaged database for SCGD originally compiled by the Company for all accounts from inception through December 31, 1998. Foster Associates appended unaged transactions for 1999-2001 to this database and reconciled the 1978-2001 activity year total transactions to Company ledger reports. The unaged database provided the basis for parameter analysis and estimation. Additionally, Foster Associates initiated an aged transaction database for all accounts beginning in 1999. The aged database was reconciled to Company ledger reports for activity years 1999-2001 and to the CPR age distribution at December 31, 2001. The resulting database provided the age distributions used for accrual computations in the 2002 depreciations study.

Q. DID FOSTER ASSOCIATES CONDUCT A STATISTICAL LIFE ANALYSIS FOR AGD?

Yes, we did. As discussed in Exhibit CCC-REW-2, two different semi-actuarial techniques known as the Simulated Plant-Record (SPR) method and the Computed Mortality method were used in the AGD study to analyze both aged and unaged plant accounts. Aged plant accounts were also analyzed using a technique in which first, second and third degree polynomials were fitted to a set of observed retirement ratios. The resulting function can be expressed in terms of a survivorship function which is numerically integrated to obtain an estimate of the average service life. The smoothed survivorship function is then fitted by a weighted least-squares procedure to the Iowa-curve family to obtain a mathematical description or classification of the dispersion characteristics of the data. Service life indications derived from the statistical analyses were blended with informed judgment and expectations about the future to obtain an appropriate projection life curve for each plant category.

Q. IN YOUR OPINION, WOULD IT BE APPROPRIATE TO ADOPT INDUSTRY STATISTICS AS A SPECIFICATION OF PARAMETERS FOR AGD?

A. No, it would not. The most that can be said of industry statistics is that they reveal the broad range of projection lives, projection curves and net salvage rates used by the reporting companies. While it would serve no useful purpose, reported statistics are not averaged to produce an industry standard. Absent a knowledge and understanding of how these statistics were derived and the composition of the plant accounts they are intended to describe, it is impossible to establish the comparability needed to apply industry statistics to another company. Factors that produce unique parameters for a reporting company include: the definition of retirements units; how retirement units are priced; capitalization policies; maintenance polices; age and physical condition of plant facilities; and the accounting treatment of transfers, adjustments, third-party reimbursements and equipment reuse. Reported industry statistics also reflect the application of informed judgment and future expectations unique to a specific company. It is the opinion of Foster Associates that industry statistics should not be adopted as parameters for AGD.

Q. DID FOSTER ASSOCIATES CONDUCT A NET SALVAGE ANALYSIS FOR AGD?

A. Yes, we did. As discussed in Exhibit CCC-REW-2, a traditional, historical analysis using a five-year moving average of the ratio of realized salvage and removal expense to the associated retirements was used in this study to a) estimate a realized net salvage rate; b) detect the emergence of historical trends; and c) establish a basis for estimating a future net salvage rate. Cost of removal and salvage opinions obtained from AGD operating personnel were blended with judgment and historical net salvage indications in developing estimates of the future.

The average net salvage rate for an account was estimated using direct dollar weighting of historical retirements with the historical net salvage rate, and future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate.

Q. DID FOSTER ASSOCIATES CONDUCT AN ANALYSIS OF THE RECORDED DEPRECIATION RESERVE FOR AGD?

A. Yes, we did. Statement C (page 19) of Exhibit CCC-REW-2 provides a comparison of the computed and recorded reserves for NAGD on December 31, 2001. The recorded reserve was $44,595,254 or 21.6 percent of the depreciable plant investment. The corresponding computed reserve is $36,110,001 or 17.5 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $8,485,253 will be amortized over the composite weighted-average remaining life of each rate category using the remaining life depreciation rates proposed in this study.

Statement C (page 24) of Exhibit CCC-REW-2 provides a comparison of the computed and recorded reserves for SCGD at December 31, 2001. The recorded reserve was $6,458,801 or 49.5 percent of the depreciable plant investment. The corresponding computed reserve is $4,325,143 or 33.1 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $2,133,658 will be amortized over the composite weighted-average remaining life of each rate category using the remaining-life depreciation rates proposed in this study.

Q. IS FOSTER ASSOCIATES RECOMMENDING A REBALANCING OF RESERVES FOR AGD?

A. Yes, we are. A redistribution of recorded reserves is particularly appropriate for AGD. Considerable time has elapsed since the adoption of the parameters used to develop AGD's current depreciation rates and implied reserve imbalances have been created by the now available age distributions from which theoretical reserves were derived. Reserves should also be realigned in this study to reflect implementation of the vintage group procedure and the parameters recommended in developing revised remaining-life depreciation rates. A redistribution of the recorded reserve will provide AGD a restated reserve balance for each primary account consistent with the parameters and depreciation system proposed in the 2002 study.

Foster Associates is recommending a rebalancing or redistribution of recorded reserves among primary accounts within each of the functional categories. A redistribution for each function (*i.e.*, Transmission, Distribution, General and CIAC) was achieved by multiplying the calculated reserve for each primary account within a function by the ratio of the function total recorded reserve to the function total calculated reserve. The sum of the redistributed reserves within a function is, therefore, equal to the function total recorded depreciation reserve before the redistribution. CIAC reserves for distribution accounts were combined with the function plant reserves to achieve a rebalancing between the plant and the CIAC reserves.

Q. WOULD YOU PLEASE DESCRIBE THE DEPRECIATION SYSTEM CURRENTLY APPROVED BY THE COMMISSION FOR AGD?

A. AGD is presently using a depreciation system composed of the straight-line method, broad group procedure, and remaining-life technique. The level of asset grouping identified in the broad group procedure is the total plant in service from all vintages in an account. Each vintage is estimated to have the same average service life. The remaining life of each vintage is estimated from a projection life curve and the attained age of the vintage. The average remaining life for a broad-group plant account or rate category is a direct, dollar-weighted average of the remaining life of each vintage. The weights used in this calculation are the vintage survivors at the beginning of the study year. The formulation of an account depreciation accrual rate using the straight-line method, broad group procedure, and remaining-life technique is given by:

$$Accrual\ Rate = \frac{1.0 - Reserve\ Ratio - Future\ Net\ Salvage\ Rate}{Remaining\ Life}.$$

Q. IS FOSTER ASSOCIATES RECOMMENDING A CHANGE IN THE DEPRECIATION SYSTEM FOR AGD?

A. Yes, we are. It is the opinion of Foster Associates that the objectives of depreciation accounting can be more nearly achieved using the vintage group procedure combined with the remaining life technique. Unlike the broad group procedure in which each vintage is estimated to have the same average service life, consideration is given to the realized life of each vintage when average service lives and remaining lives are derived using the vintage group procedure. The vintage group procedure distinguishes average service lives among vintages and composite life statistics are computed for each plant account. The formulation of an account accrual rate using the straight-line method, vintage group procedure, remaining-life technique is identical to the broad group procedure. The distinguishing feature is how the composite remaining life statistic is derived for each plant account. Depreciation rates in the 2002 study were developed using the recommended system composed of the straight-line method, vintage-group procedure and remaining-life technique.

IV. RECOMMENDATIONS

Q. WOULD YOU PLEASE SUMMARIZE THE DEPRECIATION RATES AND ACCRUALS FOSTER ASSOCIATES IS RECOMMENDING FOR AGD?

A. Table 2 provides a summary of the changes in annual rates and accruals for NAGD resulting from adoption of the parameters and depreciation system recommended in this study

Function	Accrual Rate			2002 Annualized Accrual		
	Present	Proposed	Differ-ence	Present	Proposed	Difference
Transmission	2.63%	1.59%	-1.04%	$291,773	$176,726	($115,047)
Distribution	2.99%	2.33%	-0.66%	5,605,068	4,365,484	(1,239,584)
General	9.55%	7.41%	-2.14%	1,564,730	1,214,201	(350,529)
CIAC	2.63%	1.60%	-1.03%	(210,332)	(127,829)	82,503
Total Utility	3.51%	2.72%	-0.79%	$7,251,239	$5,628,582	($1,622,657)

TABLE 2. NAGD RATES AND ACCRUALS

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.72 percent. Depreciation expense is presently accrued at an equivalent composite rate of 3.51 percent. The recommended change in the composite depreciation rate is, therefore, a decrease of 0.79 percentage points.

A continued application of rates currently prescribed would provide annualized depreciation expense of $7,251,239 compared to an annualized expense of $5,628,582 using the rates developed in this study. The proposed 2002 expense decrease is $1,622,657. Of this decrease, $500,992 represents amortization of a $8,485,253 reserve imbalance. The remaining portion of the decrease is attributable to changes in service life and net salvage parameters. Of the 24 primary accounts included in the NAGD study, Foster Associates is recommending rate reductions for 18 accounts and rate increases for 6 accounts.

Table 3 provides a summary of the changes in annual rates and accruals resulting from an application of the proposed parameters and depreciation system to SCGD.

Function	Accrual Rate			2002 Annualized Accrual		
	Present	Proposed	Differ-ence	Present	Proposed	Difference
Transmission	2.73%	0.84%	-1.89%	$8,547	$2,629	($5,918)
Distribution	3.71%	1.93%	-1.78%	478,578	249,655	(228,923)
General	3.33%	4.00%	0.67%	10,687	12,833	2,146
CIAC	3.27%	1.56%	-1.71%	(15,676)	(7,463)	8,213
Total Utility	3.69%	1.97%	-1.72%	$482,136	$257,654	($224,482)

TABLE 3. SCGD RATES AND ACCRUALS

The composite accrual rate recommended for SCGD is 1.97 percent. The current equivalent rate is 3.69 percent. The recommended change in the composite rate is a decrease of 1.72 percentage points.

A continued application of rates currently applied would provide annualized depreciation expense of $482,136 compared to an annualized expense of $257,654 using the proposed rates. The resulting 2002 expense decrease is $224,482. Of this decrease, $55,058 represents amortization of a $2,133,658 reserve imbalance. The remaining portion of the decrease is attributable to changes in service life and net salvage parameters, and adoption of amortization accounting for selected general support assets. Foster Associates is recommending rate reductions for 13 accounts and rate increases for 7 accounts.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

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Education

1961 - 1964 Valparaiso University
Major: Electrical Engineering

1965 Iowa State University
B.S., Engineering Operations

1968 Iowa State University
M.S., Engineering Valuation
Thesis: The Multivariate Normal Distribution and the Simulated Plant Record Method of Life Analysis

1977 Iowa State University
Ph.D., Engineering Valuation
Minor: Economics
Dissertation: A Comparative Analysis of Various Estimates of the Hazard Rate Associated With the Service Life of Industrial Property

Employment

1996 - Present Foster Associates, Inc.
Executive Vice President

1988 - 1996 Foster Associates, Inc.
Senior Vice President

1979 - 1988 Foster Associates, Inc.
Vice President

1978 - 1979 Northern States Power Company
Assistant Treasurer

1974 - 1978 Northern States Power Company
Manager, Corporate Economics

1972 - 1974 Northern States Power Company
Corporate Economist

1970 - 1972 Iowa State University
Graduate Student and Instructor

1968 - 1970 Northern States Power Company
Valuation Engineer

1965 - 1968 Iowa State University
Graduate Student and Teaching Assistant

Publications

A New Set of Generalized Survivor Tables, Journal of the Society of Depreciation Professionals, October, 1992.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, Journal of the Society of Depreciation Professionals, December, 1989.

Standards for Depreciation Accounting Under Regulated Competition, paper presented at The Institute for Study of Regulation, Rate Symposium, February, 1985.

The Economics of Price-Level Depreciation, paper presented at the Iowa State University Regulatory Conference, May, 1981.

Depreciation and the Discount Rate for Capital Investment Decisions, paper presented at the National Communications Forum - National Electronics Conference, October 1979.

A Computerized Method for Generating a Life Table From the 'h-System' of Survival Functions, paper presented at the American Gas Association - Edison Electric Institute Depreciation Accounting Committee Meeting, December, 1975.

The Problem With AFDC is ..., paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1973.

The Simulated Plant-Record Method of Life Analysis, paper presented at the Missouri Public Service Commission Regulatory Information Systems Conference, May, 1971.

Simulated Plant-Record Survivor Analysis Program (User's Manual), special report published by Engineering Research Institute, Iowa State University, February, 1971.

A Test Procedure for the Simulated Plant-Record Method of Life Analysis, Journal of the American Statistical Association, September, 1970.

Modeling the Behavior of Property Records, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1970.

A Technique for Simulating the Retirement Experience of Limited-Life Industrial Property, paper presented at the National Conference of Electric and Gas Utility Accountants, May, 1969.

How Dependable are Simulated Plant-Record Estimates?, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, April, 1968.

Expert Opinion

Alabama Public Service Commission, Docket No. 18488, General Telephone Company of the Southeast; testimony concerning engineering economy study techniques.

Alabama Public Service Commission, Docket No. 20208, General Telephone Company of the South; testimony concerning the equal-life group procedure and remaining-life technique.

Alberta Energy and Utilities Board, Case No. RE95081, Edmonton Power Inc.; rebuttal evidence concerning appropriate depreciation rates.

Alberta Energy and Utilities Board, 1999/2000 General Tariff Application, Edmonton Power Inc.; direct and rebuttal evidence concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. T-01051B-97-0689, U S West Communications, Inc.; testimony concerning appropriate depreciation rates.

California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.

Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.

Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.

Delaware Public Service Commission, Docket No. 82-32, Diamond State Telephone Company; testimony concerning the equal-life group procedure and remaining-life technique.

Public Service Commission of the District of Columbia, Formal Case No. 842, District of Columbia Natural Gas; testimony concerning depreciation rates.

Federal Communications Commission, Prescription of Revised Depreciation Rates for AT&T Communications; statement concerning depreciation, regulation and competition.

Federal Communications Commission, Petition for Modification of FCC Depreciation Prescription Practices for AT&T; statement concerning alignment of depreciation expense used for financial reporting and regulatory purposes.

Federal Communications Commission, Docket No. 99-117, Bell Atlantic; affidavit concerning revenue requirement and capital recovery implications of omitted plant retirements.

Federal Energy Regulatory Commission, Docket No. ER95-267-000, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. RP89-248, Mississippi River Transmission Corporation; rebuttal testimony concerning appropriateness of net salvage component in depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER91-565, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER78-291, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Energy Regulatory Commission, Docket Nos. RP80-97 and RP81-54, Tennessee Gas Pipeline Company; testimony concerning offshore plant depreciation rates.

Federal Power Commission, Docket No. E-8252, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. E-9148, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. ER76-818, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Power Commission, Docket No. RP74-80, *Northern* Natural Gas Company; testimony concerning depreciation expense.

Public Utilities Commission of the State of Hawaii, Docket No. 00-0309, The Gas Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of Hawaii, Docket No. 94-0298, GTE Hawaiian Telephone Company Incorporated; testimony concerning the need for shortened service lives and disclosure of asset impairment losses.

Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.

Illinois Commerce Commission, Docket No. 94-0481, Citizens Utilities Company of Illinois; rebuttal testimony concerning applications of the Simulated Plant-Record method of life analysis.

Iowa State Commerce Commission, Docket No. RPU 82-47, North Central Public Service Company; testimony on depreciation rates.

Iowa State Commerce Commission, Docket No. RPU 84-34, General Telephone Company of the Midwest; testimony concerning the remaining-life technique and the equal-life group procedure.

Iowa State Utilities Board, Docket No. DPU-86-2, Northwestern Bell Telephone Company; testimony concerning capital recovery in competition.

Iowa State Utilities Board, Docket No. RPU-84-7, Northwestern Bell Telephone Company; testimony concerning the deduction of a reserve deficiency from the rate base.

Iowa State Utilities Board, Docket No. DPU-88-6, U S WEST Communications; testimony concerning depreciation subject to refund.

Iowa State Utilities Board, Docket No. RPU-90-9, Central Telephone Company of Iowa; testimony concerning depreciation rates.

Iowa State Utilities Board, Docket No. RPU-93-9, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. DPU-96-1, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.

Massachusetts Department of Public Utilities, Case No. DPU 91-52, Massachusetts Electric Company; testimony supporting proposed depreciation rates which include a net salvage component.

Michigan Public Service Commission, Case No. U-12395, Michigan Gas Utilities; testimony supporting proposed depreciation rates including amortization accounting and redistribution of recorded reserves.

Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.

Michigan Public Service Commission, Case No. U-7134, General Telephone Company of Michigan; testimony concerning the equal-life group depreciation procedure.

Minnesota District Court. In Re: Northern States Power Company v. Ronald G. Blank, *et. al.* File No. 394126; testimony concerning depreciation and engineering economics.

Minnesota Public Service Commission, Docket No. E-611, Northern

States Power Company; testimony concerning rate of return and general financial requirements.

Minnesota Public Service Commission, Docket No. E-1086, Northern States Power Company; testimony concerning depreciation rates.

Minnesota Public Service Commission, Docket No. G-1015, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.

Public Service Commission of the State of Missouri, Case No. GO-97-79, Laclede Gas Company; rebuttal testimony concerning adequacy of database for conducting depreciation studies.

Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.

Public Service Commission of the State of Montana, Docket No. 88.2.5, Mountain State Telephone and Telegraph Company; rebuttal testimony concerning the equal-life group procedure and amortization of reserve imbalances.

Montana Public Service Commission, Docket No. D95.9.128, The Montana Power Company; testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 92-7002, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 91-5054, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

New Hampshire Public Utilities Commission, Docket No. DR95-169, Granite State Electric Company; testimony supporting proposed net salvage rates.

New Jersey Board of Public Utilities, Docket No. GR 87060552, New Jersey Natural Gas Company; testimony concerning depreciation rates.

New Jersey Board of Regulatory Commissioners, Docket No. GR93040114J, New Jersey Natural Gas Company; testimony concerning depreciation rates.

North Carolina Utilities Commission, Docket No. E-7, SUB 487, Duke Power Company; rebuttal testimony ong proposed depreciation rates.

North Carolina Utilities Commission, Docket No. P-19, SUB 207, General Telephone Company of the South; rebuttal testimony concerning the equal-life group depreciation procedure.

North Dakota Public Service Commission, Case No. 8860, Northern States Power Company; testimony concerning general financial requirements.

North Dakota Public Service Commission, Case No. 9634, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9666, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9741, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Ontario Energy Board, E.B.R.O. 385, Tecumseh Gas Storage Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 388, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 456, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 476-03, Union Gas Limited; testimony concerning depreciation rates.

Public Utilities Commission of Ohio, Case No. 81-383-TP-AIR, General Telephone Company of Ohio; testimony in support of the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 82-886-TP-AIR, General Telephone Company of Ohio; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 84-1026-TP-AIR, General Telephone Company of Ohio; testimony in support of the equal-life group procedure and the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 81-1433, The Ohio Bell Telephone Company; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 83-300-TP-AIR, The Ohio Bell Telephone Company; testimony concerning straight-line age-life depreciation.

Public Utilities Commission of Ohio, Case No. 84-1435-TP-AIR, The Ohio Bell Telephone Company; testimony in support of test period depreciation expense.

Public Utilities Commission of Oregon, Docket No. UM 204, GTE of the Northwest; testimony concerning the theory and practice of depreciation accounting under public utility regulation.

Public Utilities Commission of Oregon, Docket No. UM 840, GTE Northwest Incorporated; rebuttal testimony concerning principles of capital recovery.

Pennsylvania Public Utility Commission, Docket No. R-80061235, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811512, General Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811819, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-822109, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique.

Pennsylvania Public Utility Commission, Docket No. R-850229, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique and the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. C-860923, The Bell Telephone Company of Pennsylvania; testimony concerning capital recovery under competition.

Rhode Island Public Utilities Commission, Docket No. 2290, The Narragansett Electric Company; testimony supporting proposed net salvage rates and depreciation rates.

South Carolina Public Service Commission, Docket No. 91-216-E, Duke Power Company; testimony supporting proposed depreciation rates.

State of Vermont Public Service Board, Docket No. 6596, Citizens Communications Company – Vermont Electric Division, testimony supporting recommended depreciation rates.

Public Utilities Commission of the State of South Dakota, Case No. F-3062, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Public Utilities Commission of the State of South Dakota, Case No. F-3188, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Securities and Exchange Commission, File No. 3-5749, Northern States Power Company; testimony concerning the financial and ratemaking implications of an affiliation with Lake Superior District Power Company.

Tennessee Public Service Commission, Docket No. 89-11041, United Inter-Mountain Telephone Company; testimony concerning depreciation principles and capital recovery under competition.

Public Service Commission of Wisconsin, Docket No. 2180-DT-3, General Telephone Company of Wisconsin; testimony concerning the equal-life group depreciation procedure.

Other Consulting Activities

Moran Towing Corporation. In Re: Barge TEXAS-97 CIV. 2272 (ADS) and Tug HEIDE MORAN – 97 CIV. 1947 (ADS), United States District Court, Southern District of New York.

United States Telephone Association (USTA), Depreciation Training Seminar, November 1999.

Affidavit on behalf of Continental Cablevision, Inc. and its operating cable television systems regarding basic broadcast tier and equipment and installation cost-of-service rate justification.

Office of Chief Counsel, Internal Revenue Service. In Re: Kansas City Southern Railway Co., et. al. Docket Nos. 971-72, 974-72, and 4788-73.

Office of Chief Counsel, Internal Revenue Service. In Re: Northern Pacific Railway Co., Docket No. 4489-69.

United States Department of Justice. In Re: Burlington Northern Inc. v. United States, Ct. Cl. No. 30-72.

Faculty

Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. (1980 - 1999)

Depreciation Advocacy Workshop, a three-day team-training workshop on preparation, presentation, and defense of contested depreciation issues, sponsored by Gilbert Associates, Inc., October, 1979.

Corporate Economics Course, Employee Education Program, Northern States Power Company. (1968 - 1979)

Perspectives of Top Financial Executives, Course No. 5-300, University of Minnesota, September, 1978.

Depreciation Programs for public utility commissions, companies, and consultants, jointly sponsored by Western Michigan University and Michigan Technological University, 1973.

Professional Associations

Advisory Committee to the Institute for Study of Regulation, sponsored by the American University and The University of Missouri-Columbia.

American Economic Association.

American Gas Association - Edison Electric Institute Depreciation Accounting Committee.

Board of Directors, Iowa State Regulatory Conference.

Edison Electric Institute, Energy Analysis Division, Economic Advisory Committee, 1976-1980.

Financial Management Association.

The Institute of Electrical and Electronics Engineers, Inc., Power Engineering Society, Engineering and Planning Economics Working Group.

Midwest Finance Association.

Society of Depreciation Professionals (Founding Member and Chairman, Policy Committee

Moderator

Depreciation Open Forum, Iowa State University Regulatory Conference, May 1991.

The Quantification of Risk and Uncertainty in Engineering Economic Studies, Iowa State University Regulatory Conference, May 1989.

Plant Replacement Decisions with Added Revenue from New Service Offerings, Iowa State University Regulatory Conference, May 1988.

Economic Depreciation, Iowa State University Regulatory Conference, May 1987.

Opposing Views on the Use of Customer Discount Rates in Revenue Requirement Comparisons, Iowa State University Regulatory Conference, May 1986.

Cost of Capital Consequences of Depreciation Policy, Iowa State University Regulatory Conference, May 1985.

Concepts of Economic Depreciation, Iowa State University Regulatory Conference, May 1984.

Ratemaking Treatment of Large Capacity Additions, Iowa State University Regulatory Conference, May 1983.

The Economics of Excess Capacity, Iowa State University Regulatory Conference, May 1982.

New Developments in Engineering Economics, Iowa State University Regulatory Conference, May 1980.

Training in Engineering Economy, Iowa State University Regulatory Conference, May 1979.

The Real Time Problem of Capital Recovery, Missouri Public Service Commission, Regulatory Information Systems Conference, September 1974.

Speaker

Valuation Applications of Depreciation, Society of Depreciation Professionals Annual Meeting, September 2001.

Capital Asset and Depreciation Accounting, City of Edmonton Value Engineering Workshop, April 2001.

A Valuation View of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, October 1999.

Capital Recovery in a Changing Regulatory Environment, Pennsylvania Electric Association Financial-Accounting Conference, May 1999.

Depreciation Theory and Practice, Southern Natural Gas Company Accounting and Regulatory Seminar, March 1999.

Depreciation Theory Applied to Special Franchise Property, New York Office of Real Property Services, March 1999.

Capital Recovery in a Changing Regulatory Environment, PowerPlan Consultants Annual Client Forum, November 1998.

Economic Depreciation, AGA Accounting Services Committee and EEI Property Accounting and Valuation Committee, May 1998.

Discontinuation of Application of FASB Statement No. 71, Southern Natural Gas Company Accounting Seminar, April 1998.

Forecasting in Depreciation, Society of Depreciation Professionals Annual Meeting, September 1997.

Economic Depreciation In Response to Competitive Market Pricing, 1997 TELUS Depreciation Conference, June 1997.

Valuation of Special Franchise Property, City of New York, Department of Finance Valuation Seminar, March 1997.

Depreciation Implications of FAS Exposure Draft 158-B, 1996 TLG Decommissioning Conference, October 1996.

Why Economic Depreciation?, American Gas Association Depreciation Accounting Committee Meeting, August 1995.

The Theory of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

Valuation Methods for Regulated Utilities, GTE Capital Recovery Managers Conference, January 1988.

Depreciation Principles and Practices for REA Borrowers, NRECA 1985 National Accounting and Finance Conference, September 1985.

Depreciation Principles and Practices for REA Borrowers, Kentucky Association of Electric Cooperatives, Inc., Summer Accountants Association Meeting, June 1985.

Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

Software for Conducting Depreciation Studies on a Personal Computer, United States Independent Telephone Association, September 1984.

Depreciation—An Assessment of Current Practices, NRECA 1983 National Accounting and Finance Conference, September 1983

Depreciation—An Assessment of Current Practices, REA National Field Conference, September 1983.

An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

Depreciation Practices for Gas Utilities, Regulatory Committee of the Canadian Gas Association, September 1981.

Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.

Honors and Awards

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

June 2002

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Exhibit CCC-REW-2

2002 Depreciation Rate Study

Citizens Communications Company

— Northern Arizona Gas Division
— Santa Cruz Gas Division

Prepared by
Foster Associates, Inc.

CONTENTS

EXECUTIVE SUMMARY

INTRODUCTION

This report presents a review and update of depreciation rates and parameters for utility plant owned by Citizens Communications Company (Citizens) – Northern Arizona Gas Division (NAGD) and recommended rates and parameters for Citizens – Santa Cruz Gas Division (SCGD). Depreciation studies for the Citizens Arizona Gas Divisions (AGD) were conducted by Foster Associates, Inc., over the period February 2002 through mid-June 2002.

Foster Associates, Inc. is a public utility economic consulting firm headquartered in Bethesda, Maryland offering economic research and consulting services on issues and problems arising from governmental regulation of business. The areas of specialization supported by the Fort Myers office include property life forecasting, technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken depreciation engagements for both public and privately owned corporations including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

Depreciation rates currently used by NAGD were developed in a 1993 study conducted by the Company, based on December 31, 1992 plant and depreciation reserve balances. With the exception of Account 376 (Distribution Mains) and Account 380 (Distribution Services), the Arizona Corporation Commission (ACC) prescribed the depreciation rates and parameters proposed by NAGD in Docket No. E-1032 (Decision No. 58664). The ACC found that a 45-year projection life was appropriate for Account 376 and a future net salvage rate of –130 percent was appropriate for Account 380. NAGD had proposed a 40-year projection life for Account 376 and a future net salvage rate of –150 percent for Account 380.

Depreciation rates currently used by SCGD were developed in a 1979 study, based on December 31, 1978 plant and depreciation reserve balances. Foster Associates was unable to review the 1979 depreciation rate study or an ACC order prescribing current depreciation rates for SCGD. Current parameters were obtained from an attachment to a letter of correspondence dated May 26, 1987.

The principal findings and recommendations of the NAGD Depreciation Rate Study are summarized in the Statements section of this report. Statement A provides a comparative summary of present and proposed annual depreciation rates for each rate category. Statement B provides a comparison of present and proposed annual depreciation accruals. Statement C provides a comparison of the computed, recorded and redistributed depreciation reserves for each rate category. Statement D provides a summary of the components used to obtain a weighted-average net salvage rate for each plant account. Statement E provides a comparative summary of present and proposed parameters including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates. A companion set of statements for SCGD is also contained in the Statement section of this report.

SCOPE OF STUDY

The principal activities undertaken in the course of the current study included:

- Collection of plant and net salvage data;
- Reconciliation of data to the official records of the Company;
- Discussions with Citizens plant accounting personnel;
- Field inspections and discussions with NAGD and SCGD operating personnel;
- Estimation of projection lives, retirement dispersion patterns and future net salvage rates;
- Computation of average net salvage rates;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

DEPRECIATION SYSTEM

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight-line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub-grouping of assets within a plant category. The level of grouping specifies the weighting used to obtain composite life statistics for an account. A depreciation technique (*e.g.*, remaining-life) describes the life statistic used in the system.

Both NAGD and SCGD are presently using a depreciation system composed of the straight-line method, broad group procedure, and remaining-life technique for all plant categories with the exception of Account 392.00 Transportation Equipment. The Company is currently using an item procedure for transportation equipment. Depreciation rates proposed in this study were derived from a system composed of the straight-line method, vintage group procedure and remaining-life technique for all plant categories. Account 392 was excluded from the study.

The matching and expense recognition principles of accounting provide that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting can be more nearly achieved using the vintage-group procedure combined with the remaining-life technique. Unlike the broad group procedure in which each vintage is estimated to have the same average service life, the vintage group procedure distinguishes average service lives among vintages and provides cost apportionment over the estimated weighted-average remaining life or average life of a rate category.

The level of asset grouping identified in the broad group procedure is the total plant in service from all vintages in an account. Each vintage is estimated to have the same average service life. It is highly unlikely, therefore, that compensating deviations (*i.e.,* over and underestimates of average service life) will be created among vintages to achieve cost allocation over the average service life of each vintage. The level of asset grouping identified in the vintage group procedure is the plant in service from each vintage. Average service lives are estimated independently for each vintage and composite life statistics are computed for each plant account. It is more likely, therefore, that compensating deviations will be created with a vintage group procedure than with a broad group procedure.

Although the emergence of economic factors such as bypass and incentive forms of regulation may ultimately encourage abandonment of the straight-line method, no attempt was made in the current study to address this concern.

PROPOSED DEPRECIATION RATES

Table 1 provides a summary of the changes in annual rates and accruals for NAGD resulting from adoption of the parameters and depreciation system recommended in this study.

Rates and Accruals

Function	Accrual Rate			2002 Annualized Accrual		
	Present	Proposed	Difference	Present	Proposed	Difference
Transmission	2.63%	1.59%	-1.04%	$291,773	$176,726	($115,047)
Distribution	2.99%	2.33%	-0.66%	5,605,068	4,365,484	(1,239,584)
General	9.55%	7.41%	-2.14%	1,564,730	1,214,201	(350,529)
CIAC	2.63%	1.60%	-1.03%	(210,332)	(127,829)	82,503
Total Utility	3.51%	2.72%	-0.79%	$7,251,239	$5,628,582	($1,622,657)

TABLE 1. NAGD RATES AND ACCRUALS

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.72 percent. Depreciation expense is presently accrued at an equivalent composite rate of 3.51 percent. The recommended change in the composite depreciation rate is, therefore, a decrease of 0.79 percentage points.

A continued application of rates currently prescribed would provide annualized depreciation expense of $7,251,239 compared to an annualized expense of $5,628,582 using the rates developed in this study. The proposed 2002 expense decrease is $1,622,657. Of this decrease, $500,992 represents amortization of a $8,485,253 reserve imbalance. The remaining portion of the decrease is attributable to changes in service life and net salvage parameters. Of the 24 primary accounts included in the NAGD study, Foster Associates is recommending rate reductions for 18 accounts and rate increases for 6 accounts.

Table 2 provides a summary of the changes in annual rates and accruals resulting from an application of the proposed parameters and depreciation system to SCGD operations.

Rates and Accruals

	Accrual Rate			2002 Annualized Accrual		
Function	**Present**	**Proposed**	**Difference**	**Present**	**Proposed**	**Difference**
Transmission	2.73%	0.84%	-1.89%	$8,547	$2,629	($5,918)
Distribution	3.71%	1.93%	-1.78%	478,578	249,655	(228,923)
General	3.33%	4.00%	0.67%	10,687	12,833	2,146
CIAC	3.27%	1.56%	-1.71%	(15,676)	(7,463)	8,213
Total Utility	3.69%	1.97%	-1.72%	$482,136	$257,654	($224,482)

TABLE 2. SCGD RATES AND ACCRUALS

The composite accrual rate recommended for SCGD is 1.97 percent. The current equivalent rate is 3.69 percent. The recommended change in the composite rate is a decrease of 1.72 percentage points.

A continued application of rates currently applied would provide annualized depreciation expense of $482,136 compared to an annualized expense of $257,654 using the proposed rates. The resulting 2002 expense decrease is $224,482. Of this decrease, $55,058 represents amortization of a $2,133,658 reserve imbalance. The remaining portion of the decrease is attributable to changes in service life and net salvage parameters, and adoption of amortization accounting for selected general support assets. Foster Associates is recommending rate reductions for 13 accounts and rate increases for 7 accounts.

Company Profile

General

Northern Arizona Gas Division (NAGD) and Santa Cruz Gas Division (SCGD) are gas operating divisions of Citizens Communications Company (Citizens) serving a large geographic area in Northern Arizona, and a smaller area in the southern part of the state. The two divisions are collectively described as the Arizona Gas Division (AGD). These counties served by AGD comprise approximately 50 percent of Arizona's geographic area. AGD is the second largest and fastest growing gas company in Arizona. Customer growth in 2000 is over 6 percent, which is four times the industry average. During 2001, AGD sold or transported over 12 billion cubic feet of gas and is one of the lowest cost energy suppliers in the state.

The rates that AGD is allowed to charge for its distribution services are regulated by the Arizona Corporation Commission (ACC).

Gas Utility Operations

The AGD has approximately 2300 miles of distribution main lines and 124,000 service lines in its current distribution system. Since Citizens acquired the NAGD system in 1991, AGD has installed approximately 850 miles of distribution main lines and 50,176 service lines.

The distribution system in Arizona is primarily new and well maintained. Approximately 54 percent of the system is steel and the remainder is plastic pipe. AGD has an on-going cathodic protection program for its steel distribution system. As a result, corrosion has all but been eliminated, substantially reducing the replacement of those systems. In addition, AGD has a continual leak survey program and implemented a more stringent classification than prescribed by minimal safety standards. This approach has greatly reduced the risk of hazard and significantly reduced the unaccounted gas, which is reported annually.

The AGD distribution system is interconnected with two separate interstate pipeline systems and AGD operates 30 interconnect points. The delivery pressures are set contractually, and range from 200 pounds per square inch gauged ("PSIG") to 1000 PSIG.

Customer Base

Ninety percent of AGD's customers are residential and nine percent are commercial, with transportation and industrial customers making up the remaining one percent. AGD provides gas to Griffith Energy Plant, a 600-megawatt combined-cycle gas turbine electric generation facility in Mohave County. Griffith is AGD's single largest customer, with annual usage of over 80 MMBtu.

The NAGD operation provides natural gas service to approximately 115,000 customers in portions of Coconino, Mohave, Navajo, and Yavapai counties. This service area includes the towns and cities of Flagstaff, Kingman, Prescott, Sedona, Show Low, Cottonwood, Clarkdale, Village of Oak Creek, Verde Village, Pinetop-Lakeside, and Camp Verde.

The SCGD serves approximately 7,000 customers in Santa Cruz County. Santa Cruz County covers 1,236 square miles and is located near the Mexico border in the southern part of the state. Communities that SCGD serves in this area include Nogales, Tubac, Patagonia, Kino Springs, and Rio Rico. Citizens' largest customer in the area is the hospital. Other commercial customers include a sterilizer of medical supplies, hotels, restaurants, and schools.

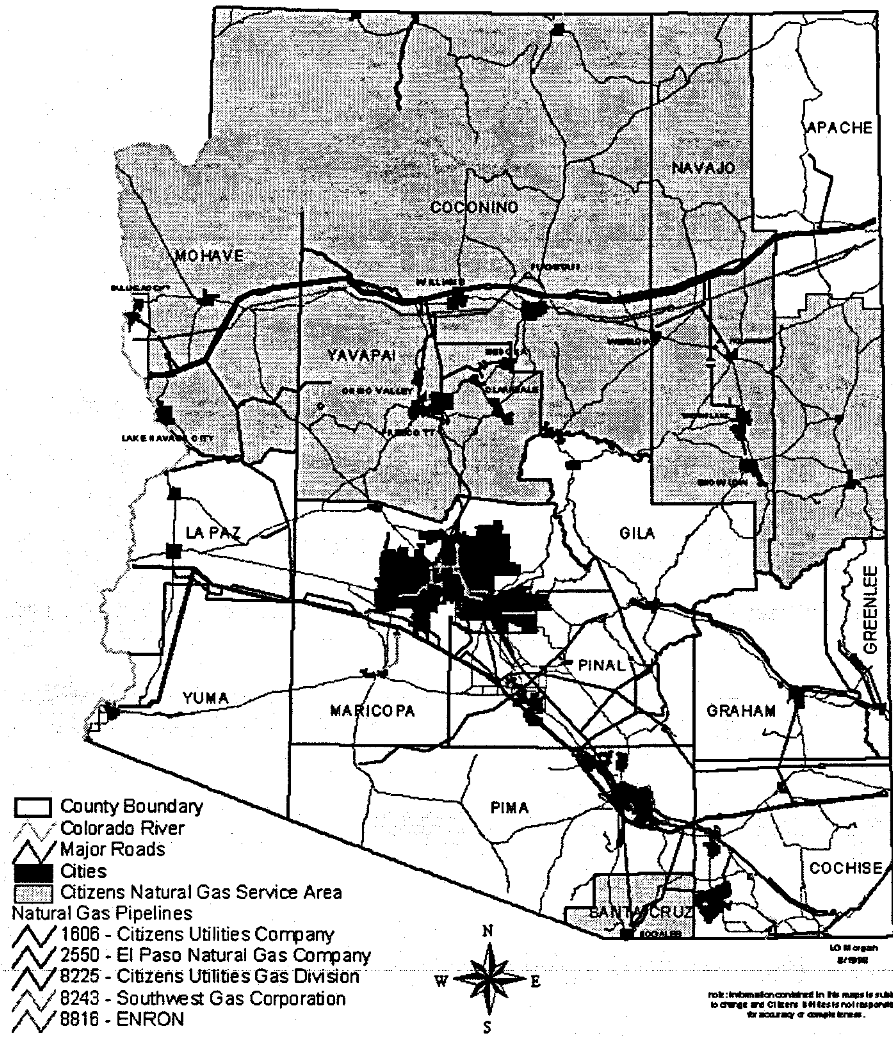


Fig. 1 AGD Service Territory

STUDY PROCEDURE

INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of the depreciation accrual and recorded depreciation reserve for each rate category. This study provides the foundation and documentation for recommended changes in the depreciation accrual rates used by Citizens for its Northern Arizona and Santa Cruz gas divisions. Rates proposed in this study are subject to approval by the ACC.

SCOPE

The steps involved in conducting a depreciation study can be grouped into five major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Net Salvage Analysis;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

The scope of the 2002 study for NAGD and SCGD included a consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing the plant in service at the beginning of the study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi-actuarial techniques*.

A far more extensive database is required to apply the statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include the age distribution of surviving plant at the beginning of the study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include the age distribution of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribution to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a data file. The data are processed by a computer program and transaction summary reports are created in a format reconcilable to the Company's official plant records. The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Company's Continuing Property Record (CPR) system provides aged transactions as described below.

Foster Associates was provided a transaction database for NAGD originally compiled by the Company and used in its 1993 study. The database had been assembled from a Southern Union Gas Company legacy system that included activity year transactions from inception through December 31, 1991. The database provided aged transactions for all plant accounts with the exception of Account 381.00 (Meters) and Account 383.00 (House Regulators), which were unaged. Foster Associates appended 1992-2001 actual aged transactions to this database and initiated aged transaction activity for the Meters and House Regulator accounts beginning in 1992. The 1992-1998 transactions were compiled from annual "CPR Plant Control" reports issued from a Computer Associates plant accounting system. The 1999-2001 transactions were compiled from the current SAP system installed in 1999 and populated with age distributions at December 31, 1998. Foster Associates reconciled the 1992-2001 activity year total transactions to Company ledger reports and the age distribution of surviving plant was reconciled to the CPR age distribution at December 31, 2001.

Foster Associates was also provided an unaged database for SCGD originally compiled by the Company for all accounts from inception through December 31, 1998. Foster Associates appended unaged transactions for 1999-2001 to this database and reconciled the 1978-2001 activity year total transactions to Company ledger reports. The unaged database provided the basis for parameter analysis and estimation. Additionally, Foster Associates initiated an aged transaction database for all accounts beginning in 1999. The aged database was reconciled to Company ledger reports for activity years 1999-2001 and to the CPR age distribution at December 31, 2001. The resulting database provided the age distributions used for accrual computations in the 2002 depreciations study.

LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two-step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and mostly concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of service life known as the *projection life* of the account. The mathematical expressions used to describe these life characteristics are known as *survival functions*.

The second step (*i.e.*, life estimation) is concerned with predicting the expected remaining life of property units still exposed to the forces of retirement. It is a process of blending the results of the life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve. The amount of weight given to the life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

The analytical methods used in a life analysis are broadly classified as actuarial and semi-actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. In other words, each property unit must be identifiable by date of installation and age at retirement. Semi-actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available. Two different semi-actuarial techniques known as the Simulated Plant-Record (SPR) method and the Computed Mortality method were used in the AGD study to analyze both aged and unaged plant accounts.

A computer program designed and developed by Foster Associates was used to conduct an SPR analysis of a) annual plant balances; b) annual retirements; and c) period retirements. The SPR annual balances method is a trial and error procedure in which a set of annual recorded balances (or cumulative retirements) for a plant category is approximated by distributing the recorded vintage additions over time according to the proportion surviving obtained from a selected family of survivor curves. An average service life can be found for each survivor curve within the family such that the sum of squared differences between the recorded balance and the simulated balances is minimized. The survivor curve and average service life which produces the smallest minimum sum of squared differences is taken as the best descriptor of the observed retirement experience.

The SPR annual retirements method is procedurally identical to the annual balances method with a substitution of plant retirements for plant balances. The life and dispersion indications obtained from the two methods may be different, however, due to the statistical property of independence associated with a series of annual retirements.

The SPR period retirements method is a variation of the annual retirements method in which the total volume of retirements over a band of years is simulated without regard to the year in which the retirements were recorded. Unlike the annual retirements method, however, the period retirements method is a two-step procedure in which the average service life for each survivor curve within the family is first determined using a zero difference criterion. A set of annual retirements is then simulated using the previously derived average service life. The survivor curve and average service life which produces the minimum sum of squared differences between the recorded retirements and the simulated retirements is ments is taken as the best descriptor of the observed retirement experience.

The objective of a computed mortality analysis is to find the average service life for a specified retirement dispersion that will simulate the age distribution of surviving plant for a series of activity years such that the sum of the simulated survivors will equal the activity year recorded plant balance. The age distribution for each activity year is obtained using a trial and error procedure in which a series of survivor ratios is applied to the age distribution derived for the prior activity year. This process is repeated until a set of survivor ratios is discovered that will produce a simulated plant balance for the activity year equal to the recorded balance. The estimated realized life for each vintage is obtained from a successive accumulation of the dollar-years of service provided by the simulated survivors. Foster Associates' computed mortality analysis program was used in this study to supplement the SPR analyses and to derive an age distribution of surviving plant for the unaged plant accounts.

An actuarial life analysis program designed and developed by Foster Associates was used in this study to analyze aged plant accounts. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age-intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age-interval and probability relationships associated with this activity. Thus, a life table minimally shows the age of each survivor and the age of each retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five available methods. The annual-rate or retirement-rate method was used in this study. The mechanics of the annual-rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This ratio (or set of ratios) is commonly referred to as the retirement ratio. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual-rate method can be applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in this study are the Iowa-type curves which are mathematically described in terms of the Pearson frequency curve family. The observed life table was smoothed by a weighted least-squares procedure in which first, second and third degree polynomials were fitted to the observed retirement ratios. The resulting function can be expressed in terms of a survivorship function which is numerically integrated to obtain an estimate of the average service life. The smoothed survivorship function is then fitted by a weighted least-squares procedure to the Iowa-curve family to obtain a mathematical description or classification of the dispersion characteristics of the data.

The set of computer programs used in this analysis provides multiple rolling-band and shrinking-band analyses of an account. Observation bands are defined in terms of a "retirement era" which means that the analysis is restricted to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling-band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking-band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. Rolling and shrinking band analyses often provide an indication of trends in the behavior of the dispersion and average service life.

Options available in the actuarial life analysis program include the width and location of both placement and observation bands; the interval of years included in a selected rolling or shrinking band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. In addition to performing the life analysis as discussed above, the programs offer tabular and graphics output as an aid in the analysis and optionally creates data output files required in the calculation of depreciation accruals.

Net Salvage Analysis

An estimate of the net salvage rate applicable to future retirements is most often obtained from an analysis of gross salvage and removal expense realized in the past. An analysis of past experience (including an examination of trends over time) provides an appropriate basis for estimating future salvage and cost of removal. However, consideration should also be given to events that may cause deviations from net salvage realized in the past. Among the factors that should be considered are the age of plant retirements; the portion of retirements likely to be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to the net salvage observed in the past.

Special consideration should also be given to the treatment of insurance proceeds and other forms of third-party reimbursements credited to the depreciation reserve. A properly conducted net salvage study will exclude such activity from the estimate of future parameters and include the activity in the computation of realized and average net salvage rates.

A traditional, historical analysis using a five-year moving average of the ratio of realized salvage and removal expense to the associated retirements was used in this study to a) estimate a realized net salvage rate; b) detect the emergence of historical trends; and c) establish a basis for estimating a future net salvage rate. Cost of removal and salvage opinions obtained from AGD operating personnel were blended with judgment and historical net salvage indications in developing estimates of the future.

The average net salvage rate for an account was estimated using direct dollar weighting of historical retirements with the historical net salvage rate, and future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate. The computation of the estimated average net salvage rate for each rate category is shown in Statement D.

DEPRECIATION RESERVE ANALYSIS

The purpose of a depreciation reserve analysis is to compare the current level of the recorded reserve with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between the required depreciation reserve and the recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to eliminate the reserve imbalance.

Unlike a recorded reserve which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measure of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of plant units still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant presently in service and the sum of the depreciation expense and net salvage that will be charged in the future if plant retirements are distributed over time according to a specified retirement frequency distribution.

The survivor curve used in the calculation of a theoretical depreciation reserve is intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be identified that will accurately describe the age of plant retirements over the complete life cycle of a vintage. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or predicted changes in the parameters chosen to describe the underlying forces of mortality.

Although reserve records are commonly maintained by various account classifications, the total reserve for a company is the most important measure of the status of the company's depreciation practices and procedures. If a company has not previously conducted statistical life studies or considered retirement dispersion in setting depreciation rates, it is likely that some accounts will be over-depreciated and other accounts will be under-depreciated relative to a calculated theoretical reserve. Differences between the theoretical reserve and the recorded reserve also will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance the total recorded reserve among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

A redistribution of recorded reserves is appropriate for AGD. Considerable time has elapsed since the adoption of the parameters used to develop AGD's current depreciation rates and implied reserve imbalances have been created by the now available age distributions from which theoretical reserves were derived. Reserves should also be realigned in this study to reflect implementation of the vintage group procedure and the parameters recommended in developing revised remaining-life depreciation rates. A redistribution of the recorded reserve will provide AGD a restated reserve balance for each primary account consistent with the parameters and depreciation system proposed in this study.

A redistribution of the recorded reserve for each function (*i.e.*, Transmission, Distribution, General and CIAC) was achieved by multiplying the calculated reserve for each primary account within a function by the ratio of the function total recorded reserve to the function total calculated reserve. The sum of the redistributed reserves within a function is, therefore, equal to the function total recorded depreciation reserve before the redistribution. CIAC reserves for distribution accounts were combined with the function plant reserves to achieve a rebalancing between the plant and the CIAC reserves.

Statement C (page 19) provides a comparison of the computed and recorded reserves for NAGD on December 31, 2001. The recorded reserve was $44,595,254 or 21.6 percent of the depreciable plant investment. The corresponding computed reserve is $36,110,001 or 17.5 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $8,485,253 will be amortized over the composite weighted-average remaining life of each rate category using the remaining life depreciation rates proposed in this study.

Statement C (page 24) provides a comparison of the computed and recorded reserves for SCGD at December 31, 2001. The recorded reserve was $6,458,801 or 49.5 percent of the depreciable plant investment. The corresponding computed reserve is $4,325,143 or 33.1 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $2,133,658 will be amortized over the composite weighted-average remaining life of each rate category using the remaining life depreciation rates proposed in this study.

Development of Accrual Rates

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non-cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is most often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time-based methods include sinking-fund, straight-line, declining balance, and sum-of-the-years' digits. The advantage of using a time-based method is that an estimate of the remaining amount of service potential an asset will provide or the amount of service actually consumed during an accounting interval is not required. Time-based allocation methods, however, do not change the goal of depreciation accounting. If it is reasonable to predict that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time-based method should be used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub-grouping of assets within a plant category. The broad group, vintage group, equal-life group, and item or unit are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. The whole life and remaining life (or expectancy) are the most common techniques.

The first step in the development of an accrual rate, therefore, is the selection of an appropriate method, procedure and technique. Depreciation rates proposed in this study were developed using a system composed of the straight-line method, vintage group procedure, remaining-life technique. It is the opinion of Foster Associates that this system will remain appropriate for AGD provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and present and proposed service life and net salvage parameters recommended for NAGD and SCGD. The content of these statements is briefly described below.

- Statement A provides a comparative summary of present and proposed annual depreciation rates using the vintage group procedure, remaining-life technique.
- Statement B provides a comparison of the present and proposed annualized 2002 depreciation accruals using the vintage group procedure, remaining-life technique.
- Statement C provides a comparison of the recorded, computed and redistributed reserves for each rate category at December 31, 2001.
- Statement D provides a summary of the components used to obtain a weighted average net salvage rate for each rate category.
- Statement E provides a comparative summary of present and proposed parameters including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates.

The present depreciation accruals shown on Statements B are the product of the plant investment (Column B) and the present depreciation rates (Column D) shown on Statement A. These are the effective rates used by the Company for the mix of investments recorded on December 31, 2001. Similarly, the proposed depreciation accruals shown on Statements B are the product of the plant investment and the proposed depreciation rates (Column H) shown on Statement A. The proposed remaining life accrual rates (Statement A) are given by:

$$\textit{Accrual Rate} = \frac{1.0 - \textit{Reserve Ratio} - \textit{Future Net Salvage Rate}}{\textit{Remaining Life}}.$$

Statements A through E

CITIZENS COMMUNICATIONS CO - Northern Arizona Gas Division Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

		Present			Proposed			
	Account Description	Rem. Life	Future Salvage	Accrual Rate	Rem. Life	Future Salvage	Reserve Ratio	Accrual Rate
	A	B	C	D	E	F	G	H
TRANSMISSION								
367.00	Mains	22.50		2.57%	55.32	-10.0%	22.30%	1.59%
369.00	Measuring and Regulating Station Equip.	19.00	-5.0%	3.32%	49.42	-5.0%	25.57%	1.61%
	Total Transmission			2.63%	54.70	-9.6%	22.55%	1.59%
DISTRIBUTION								
376.00	Mains	29.10	-10.0%	2.22%	47.62	-20.0%	19.31%	2.11%
378.00	Measuring and Regulating Equipment	17.70	-30.0%	5.73%	35.82	-30.0%	19.68%	3.08%
379.00	Measuring and Regulating Station Equip,	13.80		5.52%	35.67		14.88%	2.39%
380.00	Services	34.80	-130.0%	4.75%	44.07	-50.0%	23.32%	2.87%
381.00	Meters	26.90		2.86%	26.84		44.44%	2.07%
382.00	Meter Installations	26.90		2.86%	36.42		10.87%	2.45%
383.00	House Regulators	20.20		3.77%	27.99		24.33%	2.70%
384.00	House Regulator Installations	20.20		3.77%	33.41		5.52%	2.83%
385.00	Industrial Meas. And Reg. Station Equip.	22.70	-40.0%	3.82%	29.21	-40.0%	63.88%	2.61%
387.00	Other Equipment	19.90		3.64%	23.54		26.41%	3.13%
	Total Distribution			2.99%	44.80	-25.9%	21.49%	2.33%
GENERAL PLANT								
390.00	Structures and Improvements	10.80		3.10%	22.39		16.18%	3.74%
391.00	Office Furniture and Equipment	14.20		4.82%	19.07		18.90%	4.25%
391.10	Office Furniture and Equip. - Computers	4.80		20.00%	2.64		63.26%	13.92%
391.20	Office Furniture and Equip. - Mechanical	14.20		4.54%	21.37		3.64%	4.51%
393.00	Stores Equipment	22.30		2.27%	30.76		6.72%	3.03%
394.00	Tools, Shop & Garage Equipment	15.30		5.76%	19.76		28.82%	3.60%
395.00	Laboratory Equipment	15.30		5.76%	5.65		46.68%	9.44%
396.00	Power Operated Equipment	6.80	10.0%	24.60%	8.19	10.0%	38.59%	6.28%
397.00	Communication Equipment	7.70		4.93%	11.74		28.98%	6.05%
398.00	Miscellaneous Equipment	7.00		5.43%	22.10		11.49%	4.01%
	Total General Plant			9.55%	9.16	0.2%	31.95%	7.41%
CONTRIBUTIONS IN AID OF CONSTRUCTION								
376.09	Mains	29.10	-10.0%	2.22%	33.41		48.73%	1.53%
380.09	Services	34.80	-130.0%	4.75%	46.18		9.30%	1.96%
	Total Contributions in Aid of Construction			2.63%	36.06		42.30%	1.60%
	TOTAL UTILITY			3.51%	37.62	-24.0%	21.57%	2.72%

CITIZENS COMMUNICATIONS CO - Northern Arizona Gas Division

Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12-31-01 Plant Investment	2002 Annualized Accrual		
		Present	Proposed	Difference
A	B	D	F	H=F-D
TRANSMISSION				
367.00 Mains	$10,251,128	$263,454	$162,993	($100,461)
369.00 Measuring and Regulating Station Equip.	852,982	28,319	13,733	(14,586)
Total Transmission	$11,104,110	$291,773	$176,726	($115,047)
DISTRIBUTION				
376.00 Mains	$120,370,837	$2,672,233	$2,539,825	($132,408)
378.00 Measuring and Regulating Equipment	1,718,973	98,497	52,944	(45,553)
379.00 Measuring and Regulating Station Equip,	1,745,625	96,359	41,720	(54,639)
380.00 Services	47,317,504	2,247,581	1,358,012	(889,569)
381.00 Meters	8,591,238	245,709	177,839	(67,870)
382.00 Meter Installations	4,165,814	119,142	102,062	(17,080)
383.00 House Regulators	1,552,465	58,528	41,917	(16,611)
384.00 House Regulator Installations	281,253	10,603	7,959	(2,644)
385.00 Industrial Meas. And Reg. Station Equip.	786,344	30,038	20,524	(9,514)
387.00 Other Equipment	724,667	26,378	22,682	(3,696)
Total Distribution	$187,254,720	$5,605,068	$4,365,484	($1,239,584)
GENERAL PLANT				
390.00 Structures and Improvements	$4,553,667	$141,164	$170,307	$29,143
391.00 Office Furniture and Equipment	736,961	35,522	31,321	(4,201)
391.10 Office Furniture and Equip. - Computers	5,111,857	1,022,371	711,571	(310,800)
391.20 Office Furniture and Equip. - Mechanical	2,610,819	118,531	117,748	(783)
393.00 Stores Equipment	100,289	2,277	3,039	762
394.00 Tools, Shop & Garage Equipment	1,264,771	72,851	45,532	(27,319)
395.00 Laboratory Equipment	513,358	29,569	48,461	18,892
396.00 Power Operated Equipment	341,733	84,066	21,461	(62,605)
397.00 Communication Equipment	898,603	44,301	54,365	10,064
398.00 Miscellaneous Equipment	259,257	14,078	10,396	(3,682)
Total General Plant	$16,391,314	$1,564,730	$1,214,201	($350,529)
CONTRIBUTIONS IN AID OF CONSTRUCTION				
376.09 Mains	($6,684,422)	($148,394)	($102,272)	$46,122
380.09 Services	(1,303,950)	(61,938)	(25,557)	36,381
Total Contributions In Aid of Construction	($7,988,372)	($210,332)	($127,829)	$82,503
TOTAL UTILITY	$206,761,773	$7,251,239	$5,628,582	($1,622,657)

Statement C

CITIZENS COMMUNICATIONS CO - Northern Arizona Gas Division
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2001

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
TRANSMISSION							
367.00 Mains	$10,251,128	$2,242,404	21.87%	$1,625,289	15.85%	$2,286,373	22.30%
369.00 Measuring and Regulating Station Equip.	852,982	262,089	30.73%	155,053	18.18%	218,120	25.57%
Total Transmission	$11,104,110	$2,504,493	22.55%	$1,780,342	16.03%	$2,504,493	22.55%
DISTRIBUTION							
376.00 Mains	$120,370,837	$19,967,034	16.59%	$19,131,266	15.89%	$23,241,242	19.31%
378.00 Measuring and Regulating Equipment	1,718,973	589,533	34.30%	278,404	16.20%	338,214	19.68%
379.00 Measuring and Regulating Station Equip,	1,745,625	521,880	29.90%	213,855	12.25%	259,798	14.88%
380.00 Services	47,317,504	12,254,614	25.90%	9,083,742	19.20%	11,035,206	23.32%
381.00 Meters	8,591,238	3,413,133	39.73%	3,142,542	36.58%	3,817,655	44.44%
382.00 Meter Installations	4,165,814	388,709	9.33%	372,840	8.95%	452,938	10.87%
383.00 House Regulators	1,552,465	636,551	41.00%	310,937	20.03%	377,735	24.33%
384.00 House Regulator Installations	281,253	11,334	4.03%	12,777	4.54%	15,522	5.52%
385.00 Industrial Meas. And Reg. Station Equip.	786,344	473,929	60.27%	413,478	52.58%	502,305	63.88%
387.00 Other Equipment	724,667	172,911	23.86%	157,557	21.74%	191,405	26.41%
Total Distribution	$187,254,720	$38,429,627	20.52%	$33,117,398	17.69%	$40,232,019	21.49%
GENERAL PLANT							
390.00 Structures and Improvements	$4,553,667	$673,545	14.79%	$561,631	12.33%	$736,578	16.18%
391.00 Office Furniture and Equipment	736,961	101,518	13.78%	106,178	14.41%	139,252	18.90%
391.10 Office Furniture and Equip. - Computers	5,111,857	3,618,144	70.78%	2,465,719	48.24%	3,233,787	63.26%
391.20 Office Furniture and Equip. - Mechanical	2,610,819	67,086	2.57%	72,457	2.78%	95,027	3.64%
393.00 Stores Equipment	100,289	13,725	13.69%	5,135	5.12%	6,735	6.72%
394.00 Tools, Shop & Garage Equipment	1,264,771	239,978	18.97%	277,912	21.97%	364,481	28.82%
395.00 Laboratory Equipment	513,358	71,120	13.85%	182,710	35.59%	239,625	46.68%
396.00 Power Operated Equipment	341,733	274,430	80.31%	100,551	29.42%	131,873	38.59%
397.00 Communication Equipment	898,603	137,632	15.32%	198,563	22.10%	260,415	28.98%
398.00 Miscellaneous Equipment	259,257	40,373	15.57%	22,704	8.76%	29,776	11.49%
Total General Plant	$16,391,314	$5,237,549	31.95%	$3,993,561	24.36%	$5,237,549	31.95%
CONTRIBUTIONS IN AID OF CONSTRUCTION							
376.09 Mains	($6,684,422)	($1,353,921)	20.25%	($2,681,437)	40.11%	($3,257,491)	48.73%
380.09 Services	(1,303,950)	(222,494)	17.06%	(99,863)	7.66%	(121,316)	9.30%
Total Contributions in Aid of Construction	($7,988,372)	($1,576,415)	19.73%	($2,781,299)	34.82%	($3,378,807)	42.30%
TOTAL UTILITY	$206,761,773	$44,595,254	21.57%	$36,110,001	17.46%	$44,595,254	21.57%

CITIZENS COMMUNICATIONS CO - Northern Arizona Gas Division
Average Net Salvage

Statement D

		Plant Investment			Salvage Rate		Net Salvage			Average
	Account Description	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
	A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
TRANSMISSION										
367.00	Mains	$10,606,420	$355,292	$10,251,128	0.0%	-10.0%	$0	($1,025,113)	($1,025,113)	-9.7%
369.00	Measuring and Regulating Station Equip.	879,366	26,384	852,982	-0.5%	-5.0%	(132)	(42,649)	(42,781)	-4.9%
	Total Transmission	$11,485,786	$381,676	$11,104,110	0.0%	-9.6%	($132)	($1,067,762)	($1,067,894)	-9.3%
DISTRIBUTION										
376.00	Mains	$121,445,105	$1,074,268	$120,370,837	-17.5%	-20.0%	($187,997)	($24,074,167)	($24,262,164)	-20.0%
378.00	Measuring and Regulating Equipment	1,862,044	143,071	1,718,973	-14.0%	-30.0%	(20,030)	(515,692)	(535,722)	-28.8%
379.00	Measuring and Regulating Station Equip,	1,994,832	249,207	1,745,625	0.0%	0.0%	0	0	0	0.0%
380.00	Services	48,759,156	1,441,652	47,317,504	-6.9%	-50.0%	(99,474)	(23,658,752)	(23,758,226)	-48.7%
381.00	Meters	8,961,821	370,583	8,591,238	0.0%	0.0%	0	0	0	0.0%
382.00	Meter Installations	4,166,047	233	4,165,814	-696.8%	0.0%	(1,624)	0	(1,624)	0.0%
383.00	House Regulators	2,302,769	750,304	1,552,465	0.0%	0.0%	0	0	0	0.0%
384.00	House Regulator Installations	281,346	93	281,253	0.0%	0.0%	0	0	0	0.0%
385.00	Industrial Meas. And Reg. Station Equip.	953,846	167,502	786,344	-16.8%	-40.0%	(28,140)	(314,538)	(342,678)	-35.9%
387.00	Other Equipment	763,792	39,125	724,667	0.0%	0.0%	0	0	0	0.0%
	Total Distribution	$191,490,758	$4,236,038	$187,254,720	-8.0%	-25.9%	($337,266)	($48,563,149)	($48,900,415)	-25.5%
GENERAL PLANT										
390.00	Structures and Improvements	$5,533,569	$979,902	$4,553,667	0.0%	0.0%	$0	$0	$0	0.0%
391.00	Office Furniture and Equipment	1,061,096	324,135	736,961	0.0%	0.0%	0	0	0	0.0%
391.10	Office Furniture and Equip. - Computers	5,320,571	208,714	5,111,857	0.0%	0.0%	0	0	0	0.0%
391.20	Office Furniture and Equip. - Mechanical	2,612,964	2,145	2,610,819	0.0%	0.0%	0	0	0	0.0%
393.00	Stores Equipment	101,182	893	100,289	0.0%	0.0%	0	0	0	0.0%
394.00	Tools, Shop & Garage Equipment	1,687,493	422,722	1,264,771	-0.5%	0.0%	(2,114)	0	(2,114)	-0.1%
395.00	Laboratory Equipment	555,187	41,829	513,358	-23.4%	0.0%	(9,788)	0	(9,788)	-1.8%
396.00	Power Operated Equipment	642,577	300,844	341,733	11.7%	10.0%	35,199	34,173	69,372	10.8%
397.00	Communication Equipment	1,087,184	188,581	898,603	0.0%	0.0%	0	0	0	0.0%
398.00	Miscellaneous Equipment	270,420	11,163	259,257	11.4%	0.0%	1,273	0	1,273	0.5%
	Total General Plant	$18,872,243	$2,480,929	$16,391,314	1.0%	0.2%	$24,570	$34,173	$58,743	0.3%
CONTRIBUTIONS IN AID OF CONSTRUCTION										
376.09	Mains	($6,684,422)	$0	($6,684,422)	0.0%	0.0%	$0	$0	$0	0.0%
380.09	Services	(1,304,450)	(500)	(1,303,950)	0.0%	0.0%	0	0	0	0.0%
	Total Contributions in Aid of Construction	($7,988,872)	($500)	($7,988,372)	0.0%	0.0%	$0	$0	$0	0.0%
	TOTAL UTILITY	$213,859,915	$7,098,142	$206,761,773	-4.4%	-24.0%	($312,828)	($49,596,738)	($49,909,566)	-23.3%

CITIZENS COMMUNICATIONS CO - Northern Arizona Gas Division
Present and Proposed Parameters
Vintage Group Procedure

Statement E

Account Description	Present Parameters P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Average Salvage	Future Salvage	Proposed Parameters P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Average Salvage	Future Salvage
A	B	C	D	E	F	G	H	I	J	K	L	M
TRANSMISSION												
367.00 Mains	35.00	R2	35.00	22.50	0.0	0.0	65.00	R3	64.46	55.32	-9.7	-10.0
369.00 Measuring and Regulating Station Equip.	30.00	R5	30.00	19.00	-5.0	-5.0	60.00	R4	59.71	49.42	-4.9	-5.0
Total Transmission									64.12	54.70	-9.3	-9.6
DISTRIBUTION												
376.00 Mains	45.00	R5	45.00	29.10	-10.0	-10.0	55.00	L5	54.89	47.62	-20.0	-20.0
378.00 Measuring and Regulating Equipment	25.00	R4	25.00	17.70	-30.0	-30.0	40.00	SC	40.54	35.82	-28.8	-30.0
379.00 Measuring and Regulating Station Equip,	20.00	R4	20.00	13.80	0.0	0.0	40.00	SC	40.65	35.67		0.0
380.00 Services	44.00	S6	44.00	34.80	-130.0	-130.0	50.00	R2.5	50.10	44.07	-48.7	-50.0
381.00 Meters	39.00	R5	39.00	26.90	0.0	0.0	40.00	R5	42.32	26.84		0.0
382.00 Meter Installations	39.00	R5	39.00	26.90	0.0	0.0	40.00	R5	40.00	36.42		0.0
383.00 House Regulators	30.00	R5	30.00	20.20	0.0	0.0	35.00	R5	35.00	27.99		0.0
384.00 House Regulator Installations	30.00	R5	30.00	20.20	0.0	0.0	35.00	R5	35.00	33.41		0.0
385.00 Industrial Meas. And Reg. Station Equip.	35.00	R3	35.00	22.70	-40.0	-40.0	45.00	R1.5	45.41	29.21	-35.9	-40.0
387.00 Other Equipment	25.00	S6	25.00	19.90	0.0	0.0	30.00	S6	30.08	23.54		0.0
Total Distribution									51.70	44.80	-25.5	-25.9
GENERAL PLANT												
390.00 Structures and Improvements	27.00	S6	27.00	10.80	0.0	0.0	25.00	SC	25.54	22.39		0.0
391.00 Office Furniture and Equipment	22.00	S6	22.00	14.20	0.0	0.0	22.00	R1.5	22.28	19.07		0.0
391.10 Office Furniture and Equip. - Computers	5.00	SQ	5.00	4.80	0.0	0.0	5.00	R4	5.10	2.64		0.0
391.20 Office Furniture and Equip. - Mechanical	22.00	S6	22.00	14.20	0.0	0.0	22.00	S6	21.98	21.37		0.0
393.00 Stores Equipment	36.00	S6	36.00	22.30	0.0	0.0	35.00	SC	32.42	30.76		0.0
394.00 Tools, Shop & Garage Equipment	20.00	S6	20.00	15.30	0.0	0.0	25.00	L1	25.35	19.76	-0.1	0.0
395.00 Laboratory Equipment	20.00	S6	20.00	15.30	0.0	0.0	9.00	S4	8.93	5.65	-1.8	0.0
396.00 Power Operated Equipment	10.00	S6	10.00	6.80	10.0	10.0	12.00	L2	12.06	8.19	10.8	10.0
397.00 Communication Equipment	17.00	R5	17.00	7.70	0.0	0.0	15.00	L2	15.07	11.74		0.0
398.00 Miscellaneous Equipment	20.00	S6	20.00	7.00	0.0	0.0	25.00	S0	24.10	22.10	0.5	0.0
Total General Plant									10.61	9.16	0.3	0.2
CONTRIBUTIONS IN AID OF CONSTRUCTION												
376.09 Mains	45.00	R5	45.00	29.10	(10.0)	(10.0)	55.00	L5	55.79	33.41		0.0
380.09 Services	44.00	S6	44.00	34.80	(130.0)	(130.0)	50.00	R2.5	50.01	46.18		0.0
Total Contributions in Aid of Construction									54.82	36.06		0.0
TOTAL UTILITY									41.59	37.62	-23.3	-24.0

Statements A through E

CITIZENS COMMUNICATIONS CO - Santa Cruz Gas Division Statement A

Comparison of Present and Proposed Accrual Rates
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

	Present			Proposed			
Account Description	Rem. Life	Future Salvage	Accrual Rate	Rem. Life	Future Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
TRANSMISSION							
367.00 Mains		-5.0%	2.67%	36.86	-10.0%	79.82%	0.82%
369.00 Measuring and Regulating Equipment			4.14%	43.56	-5.0%	47.84%	1.31%
Total Transmission			2.73%	37.23	-9.8%	78.57%	0.84%
DISTRIBUTION							
375.00 Structures and Improvements			7.27%	16.64		79.21%	1.25%
376.00 Mains		-5.0%	2.99%	43.64	-20.0%	48.93%	1.63%
378.00 Meas. and Reg. Sta. Equip. - General			3.07%	31.66		38.64%	1.94%
379.00 Meas. and Reg. Sta. Equip. - City Gate			3.07%	33.75		26.38%	2.18%
380.00 Services		-25.0%	5.65%	39.69	-50.0%	47.85%	2.57%
381.00 Meters			2.58%	26.51		50.83%	1.85%
382.00 Meter Installations			2.58%	29.96		38.64%	2.05%
383.00 House Regulators			4.06%	22.87		52.16%	2.09%
384.00 House Regulator Installations			4.06%	34.50		2.14%	2.84%
Total Distribution			3.71%	39.74	-25.4%	48.50%	1.93%
GENERAL PLANT							
390.00 Structures and Improvements			3.50%	21.56		14.46%	3.97%
391.00 Office Furniture and Equipment			3.94%	25.00		15.67%	3.37%
394.00 Tools, Shop & Garage Equipment			3.39%	21.60		13.33%	4.01%
395.00 Laboratory Equipment			3.28%	16.41		42.84%	3.48%
396.00 Power Operated Equipment			0.99%	11.67	10.0%	57.20%	2.81%
397.00 Communication Equipment			4.13%	13.52		9.28%	6.71%
398.00 Miscellaneous Equipment			5.06%	20.51		17.16%	4.04%
Total General Plant			3.33%	20.35	0.6%	17.90%	4.00%
CONTRIBUTIONS IN AID OF CONSTRUCTION							
376.09 Mains		-5.0%	2.99%	50.95		22.56%	1.52%
380.09 Services		-25.0%	5.65%	44.67		16.02%	1.88%
Total Contributions in Aid of Construction			3.27%	50.14		21.86%	1.56%
TOTAL UTILITY			3.69%	38.45	-25.3%	49.45%	1.97%

CITIZENS COMMUNICATIONS CO - Santa Cruz Gas Division

Statement B

Comparison of Present and Proposed Accruals
Present: BG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12-31-01 Plant Investment	2002 Annualized Accrual Present	Proposed	Difference
A	B	D	F	H=F-D
TRANSMISSION				
367.00 Mains	$301,132	$8,040	$2,469	($5,571)
369.00 Measuring and Regulating Equipment	12,243	507	160	(347)
Total Transmission	$313,375	$8,547	$2,629	($5,918)
DISTRIBUTION				
375.00 Structures and Improvements	$8,247	$600	$103	($497)
376.00 Mains	7,444,088	222,578	121,339	(101,239)
378.00 Meas. and Reg. Sta. Equip. - General	95,923	2,945	1,861	(1,084)
379.00 Meas. and Reg. Sta. Equip. - City Gate	12,144	373	265	(108)
380.00 Services	3,571,999	201,818	91,800	(110,018)
381.00 Meters	1,118,258	28,851	20,688	(8,163)
382.00 Meter Installations	353,454	9,119	7,246	(1,873)
383.00 House Regulators	299,491	12,159	6,259	(5,900)
384.00 House Regulator Installations	3,319	135	94	(41)
Total Distribution	$12,906,924	$478,578	$249,655	($228,923)
GENERAL PLANT				
390.00 Structures and Improvements	$109,662	$3,838	$4,354	$516
391.00 Office Furniture and Equipment	10,306	406	347	(59)
394.00 Tools, Shop & Garage Equipment	146,412	4,963	5,871	908
395.00 Laboratory Equipment	15,873	521	552	31
396.00 Power Operated Equipment	20,526	203	577	374
397.00 Communication Equipment	15,513	641	1,041	400
398.00 Miscellaneous Equipment	2,263	115	91	(24)
Total General Plant	$320,555	$10,687	$12,833	$2,146
CONTRIBUTIONS IN AID OF CONSTRUCTION				
376.09 Mains	($427,901)	($12,794)	($6,504)	$6,290
380.09 Services	(51,010)	(2,882)	(959)	1,923
Total Contributions in Aid of Construction	($478,911)	($15,676)	($7,463)	$8,213
TOTAL UTILITY	$13,061,943	$482,136	$257,654	($224,482)

CITIZENS COMMUNICATIONS CO - Santa Cruz Gas Division
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2001

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
TRANSMISSION							
367.00 Mains	$301,132	$238,054	79.05%	$144,610	48.02%	$240,365	79.82%
369.00 Measuring and Regulating Equipment	12,243	8,169	66.72%	3,524	28.78%	5,857	47.84%
Total Transmission	$313,375	$246,222	78.57%	$148,134	47.27%	$246,222	78.57%
DISTRIBUTION							
375.00 Structures and Improvements	$8,247	$8,249	100.02%	$4,368	52.97%	$6,532	79.21%
376.00 Mains	7,444,088	3,400,285	45.68%	2,435,706	32.72%	3,642,452	48.93%
378.00 Meas. and Reg. Sta. Equip. - General	95,923	50,137	52.27%	24,784	25.84%	37,063	38.64%
379.00 Meas. and Reg. Sta. Equip. - City Gate	12,144	5,123	42.19%	2,143	17.64%	3,204	26.38%
380.00 Services	3,571,999	2,196,834	61.50%	1,143,060	32.00%	1,709,378	47.85%
381.00 Meters	1,118,258	425,177	38.02%	380,085	33.99%	568,395	50.83%
382.00 Meter Installations	353,454	76,446	21.63%	91,338	25.84%	136,591	38.64%
383.00 House Regulators	299,491	148,992	49.75%	104,464	34.88%	156,219	52.16%
384.00 House Regulator Installations	3,319	19	0.57%	47	1.43%	71	2.14%
Total Distribution	$12,906,924	$6,311,264	48.90%	$4,185,995	32.43%	$6,259,905	48.50%
GENERAL PLANT							
390.00 Structures and Improvements	$109,662	$22,262	20.30%	$16,871	15.38%	$15,860	14.46%
391.00 Office Furniture and Equipment	10,306	2,784	27.01%	1,718	16.67%	1,615	15.67%
394.00 Tools, Shop & Garage Equipment	146,412	2,227	1.52%	20,766	14.18%	19,522	13.33%
395.00 Laboratory Equipment	15,873	7,738	48.75%	7,234	45.57%	6,800	42.84%
396.00 Power Operated Equipment	20,526	20,526	100.00%	12,488	60.84%	11,740	57.20%
397.00 Communication Equipment	15,513	1,036	6.68%	1,531	9.87%	1,439	9.28%
398.00 Miscellaneous Equipment	2,263	792	34.98%	413	18.25%	388	17.16%
Total General Plant	$320,555	$57,364	17.90%	$61,021	19.04%	$57,364	17.90%
CONTRIBUTIONS IN AID OF CONSTRUCTION							
376.09 Mains	($427,901)	($136,616)	31.93%	($64,542)	15.08%	($96,518)	22.56%
380.09 Services	(51,010)	(19,434)	38.10%	(5,465)	10.71%	(8,173)	16.02%
Total Contributions in Aid of Construction	($478,911)	($156,049)	32.58%	($70,007)	14.62%	($104,691)	21.86%
TOTAL UTILITY	$13,061,943	$6,458,801	49.45%	$4,325,143	33.11%	$6,458,801	49.45%

CITIZENS COMMUNICATIONS CO - Santa Cruz Gas Division
Average Net Salvage

Statement D

		Plant Investment			Salvage Rate		Net Salvage			Average
	Account Description	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
	A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
TRANSMISSION										
367.00	Mains	$301,132	$0	$301,132	0.0%	-10.0%	$0	($30,113)	($30,113)	-10.0%
369.00	Measuring and Regulating Equipment	12,243	0	12,243	0.0%	-5.0%	0	(612)	(612)	-5.0%
	Total Transmission	$313,375	$0	$313,375	0.0%	-9.8%	$0	($30,725)	($30,725)	-9.8%
DISTRIBUTION										
375.00	Structures and Improvements	$8,247	$0	$8,247	0.0%	0.0%	$0	$0	$0	0.0%
376.00	Mains	7,460,777	16,689	7,444,088	-13.5%	-20.0%	(2,253)	(1,488,818)	(1,491,071)	-20.0%
378.00	Meas. and Reg. Sta. Equip. - General	103,756	7,833	95,923	0.0%	0.0%	0	0	0	0.0%
379.00	Meas. and Reg. Sta. Equip. - City Gate	12,144	0	12,144	0.0%	0.0%	0	0	0	0.0%
380.00	Services	3,576,827	4,828	3,571,999	29.2%	-50.0%	1,410	(1,786,000)	(1,784,590)	-49.9%
381.00	Meters	1,122,717	4,459	1,118,258	-1.3%	0.0%	(58)	0	(58)	0.0%
382.00	Meter Installations	353,456	2	353,454	-69.7%	0.0%	(1)	0	(1)	0.0%
383.00	House Regulators	299,491	0	299,491	-2.2%	0.0%	0	0	0	0.0%
384.00	House Regulator Installations	3,319	0	3,319	0.0%	0.0%	0	0	0	0.0%
	Total Distribution	$12,940,734	$33,810	$12,906,924	-2.7%	-25.4%	($903)	($3,274,817)	($3,275,720)	-25.3%
GENERAL PLANT										
390.00	Structures and Improvements	$109,662	$0	$109,662	0.0%	0.0%	$0	$0	$0	0.0%
391.00	Office Furniture and Equipment	15,859	5,553	10,306	0.0%	0.0%	0	0	0	0.0%
394.00	Tools, Shop & Garage Equipment	191,546	45,134	146,412	0.0%	0.0%	0	0	0	0.0%
395.00	Laboratory Equipment	16,525	652	15,873	0.0%	0.0%	0	0	0	0.0%
396.00	Power Operated Equipment	23,530	3,004	20,526	1.8%	10.0%	54	2,053	2,107	9.0%
397.00	Communication Equipment	15,513	0	15,513	0.0%	0.0%	0	0	0	0.0%
398.00	Miscellaneous Equipment	2,797	534	2,263	0.0%	0.0%	0	0	0	0.0%
	Total General Plant	$375,432	$54,877	$320,555	0.1%	0.6%	$54	$2,053	$2,107	0.6%
CONTRIBUTIONS IN AID OF CONSTRUCTION										
376.09	Mains	($427,901)	$0	($427,901)	0.0%	0.0%	$0	$0	$0	0.0%
380.09	Services	(51,010)	0	(51,010)	0.0%	0.0%	0	0	0	0.0%
	Total Contributions in Aid of Construction	($478,911)	$0	($478,911)	0.0%	0.0%	$0	$0	$0	0.0%
	TOTAL UTILITY	$13,150,630	$88,687	$13,061,943	-1.0%	-25.3%	($849)	($3,303,490)	($3,304,339)	-25.1%

CITIZENS COMMUNICATIONS CO - Santa Cruz Gas Division
Present and Proposed Parameters
Vintage Group Procedure

Statement E

		Present Parameters						Proposed Parameters					
	Account Description	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Average Salvage	Future Salvage	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Average Salvage	Future Salvage
	A	B	C	D	E	F	G	H	I	J	K	L	M
TRANSMISSION													
367.00	Mains	40.00	SQ	40.00		-5.0	-5.0	65.00	R3	65.42	36.86	-10.0	-10.0
369.00	Measuring and Regulating Equipment			30.00		0.0	0.0	60.00	R4	60.01	43.56	-5.0	-5.0
	Total Transmission									65.25	37.23	-9.8	-9.8
DISTRIBUTION													
375.00	Structures and Improvements	30.00	SQ	30.00		0.0	0.0	35.00	R4	35.38	16.64		0.0
376.00	Mains	35.00	R1	35.00		-5.0	-5.0	60.00	S5	60.00	43.64	-20.0	-20.0
378.00	Meas. and Reg. Sta. Equip. - General	30.00	R1	30.00		0.0	0.0	40.00	SC	42.69	31.66		0.0
379.00	Meas. and Reg. Sta. Equip. - City Gate	30.00	R1	30.00		0.0	0.0	40.00	SC	40.98	33.75		0.0
380.00	Services	25.00	R2	25.00		-25.0	-25.0	50.00	R2.5	50.42	39.69	-49.9	-50.0
381.00	Meters	40.00	R3	40.00		0.0	0.0	40.00	R5	40.16	26.51		0.0
382.00	Meter Installations	40.00	R3	40.00		0.0	0.0	40.00	R5	40.40	29.96		0.0
383.00	House Regulators	25.00	S1	25.00		0.0	0.0	35.00	R5	35.12	22.87		0.0
384.00	House Regulator Installations	25.00	S1	25.00		0.0	0.0	35.00	R5	35.00	34.50		0.0
	Total Distribution									53.38	39.74	-25.3	-25.4
GENERAL PLANT													
390.00	Structures and Improvements			27.00		0.0	0.0	25.00	SC	25.48	21.56		0.0
391.00	Office Furniture and Equipment	25.00	L1	25.00		0.0	0.0	30.00	S2	30.00	25.00		0.0
394.00	Tools, Shop & Garage Equipment	30.00	S6	30.00		0.0	0.0	25.00	L1	25.17	21.60		0.0
395.00	Laboratory Equipment	30.00	S6	30.00		0.0	0.0	30.00	S4	30.15	16.41		0.0
396.00	Power Operated Equipment	12.00	L3	12.00		0.0	0.0	30.00	L2	36.42	11.67	9.0	10.0
397.00	Communication Equipment	20.00	S1	20.00		0.0	0.0	15.00	L2	15.00	13.52		0.0
398.00	Miscellaneous Equipment	20.00	SQ	20.00		0.0	0.0	25.00	S0	25.09	20.51		0.0
	Total General Plant									25.25	20.35	0.6	0.6
CONTRIBUTIONS IN AID OF CONSTRUCTION													
376.09	Mains	35.00	R1	35.00		(5.0)	(5.0)	60.00	S5	60.00	50.95		0.0
380.09	Services	25.00	R2	25.00		(25.0)	(25.0)	50.00	R2.5	50.03	44.67		0.0
	Total Contributions in Aid of Construction									58.65	50.14		0.0
	TOTAL UTILITY									52.25	38.45	-25.1	-25.3

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the AGD depreciation studies to estimate appropriate projection curves, projection lives and net salvage statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes an example of the supporting schedules developed for NAGD Account 380.00 – Services. Documentation for all other plant accounts is contained in the study work papers. Supporting schedules developed in the current AGD study include:

Schedule A – Generation Arrangement;

Schedule B – Age Distribution;

Schedule C – Unadjusted Plant History;

Schedule D – Adjusted Plant History;

Schedule E – Actuarial Life Analysis;

Schedule F – Graphics Analysis;

Schedule G – Simulated Plant-Record Analysis;

Schedule H – Computed Mortality Analysis; and

Schedule I – Historical Net Salvage Analysis.

The format and content of these schedules are briefly described below.

SCHEDULE A – GENERATION ARRANGEMENT

The purpose of this schedule is to obtain appropriate weighted-average life statistics for a rate category. The weighted-average remaining-life is the sum of Column H divided by the sum of Column I. The weighted average life is the sum of Column C (adjusted for average net salvage) divided by the sum of Column I. The computed depreciation reserve can be derived from this schedule by subtracting the computed net plant (Column H) from the surviving plant (Column C) adjusted for average net salvage. The net salvage adjustment is Column C multiplied by the future net salvage rate. The computed reserve (except for rounding) is therefore given by

$$\textit{Computed Reserve} = \textit{Plant}(1.0 - \textit{Future Net Salvage}) - \textit{Computed Net Plant}.$$

The following table provides a description of each column in the generation arrangement.

Generation Arrangement

Column	Title	Description
A	Vintage	Vintage or placement year of surviving plant.
B	Age	Age of surviving plant at beginning of study year.
C	Surviving Plant	Actual dollar amount of surviving plant.
D	Average Life	Estimated average life of each vintage. This statistic is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving.
E	Remaining Life	Estimated remaining life of each vintage.
F	Net Plant Ratio	Theoretical net plant ratio of each vintage.
G	Allocation Factor	A pivotal ratio which determines the amortization period of the difference between the recorded and computed reserve.
H	Computed Net Plant	Plant in service less theoretical reserve for each vintage.
I	Accrual	Ratio of computed net plant (Column H) and remaining life (Column E).

TABLE 3. GENERATION ARRANGEMENT

SCHEDULE B – AGE DISTRIBUTION

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

The computed proportion surviving (Column D) for unaged data is derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

SCHEDULE C – UNADJUSTED PLANT HISTORY

This schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

SCHEDULE D – ADJUSTED PLANT HISTORY

This schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Ageing of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records nor in the unadjusted plant history.

SCHEDULE E – ACTUARIAL LIFE ANALYSIS

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce either a rolling-band or a shrinking-band analysis depending upon the movement of the end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling or shrinking band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

The estimated average service lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum-of-squared differences between the graduated survivor curve and the best fitting Iowa curve. A Conformance Index of zero would indicate a perfect fit.

SCHEDULE F – GRAPHICS ANALYSIS

This schedule provides a graphics plot of the observed proportion surviving for a selected placement and observation band and the projection curve and projection life selected to describe future forces of mortality.

SCHEDULE G – SIMULATED PLANT-RECORD ANALYSIS

This schedule summarizes a Simulated Plant-Record analysis using the annual balances, annual retirements, or period retirements method. The schedule ranks the six best fitting dispersions for four observation bands according to a minimum sum of squared differences criterion. An Index of Variation and a Retirement Experience are shown for each dispersion. The Index of Variation is the root mean square of the sum of differences between simulated and recorded amounts divided by the mean of the annual recorded amounts. The Retirement Experience Index is the percentage of the oldest addition in an account that would be retired from service if retirements are described by the indicated dispersion and average service life. The Combined Index is the ratio of the Index of Variation and the Retirement Experience Index.

SCHEDULE H – COMPUTED MORTALITY ANALYSIS

This schedule provides a summary of the average service life indications obtained from a computed mortality analysis of unaged retirement activity. The activity year, plant additions and adjusted plant balances used in the analysis are shown in Columns A through C. The average service life that produces an activity year computed balance (Column D) equal to the adjusted balance is shown in Column F. The dispersion selected for the analysis is shown in the title block.

SCHEDULE I - HISTORICAL NET SALVAGE ANALYSIS

This schedule provides a moving average analysis of the ratio of realized net salvage (Column I) to the associated retirements (Column B). The schedule also provides a moving average analysis of the components of net salvage related to retirements. The ratio of gross salvage to retirements is shown in Column D and the ratio of cost of removal to retirements is shown in Column G.

NORTHERN ARIZONA GAS DIVISION

Distribution Plant
Account: 380.00 Services

Dispersion: 50 - R2.5
Procedure: Vintage Group

Generation Arrangement

Vintage	December 31, 2001 Age	Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2001	0.5	8,476,447	50.00	49.53	0.9905	1.0000	8,396,301	169,528
2000	1.5	2,513,493	50.00	48.59	0.9718	1.0000	2,442,489	50,272
1999	2.5	6,104,053	50.00	47.65	0.9529	1.0000	5,816,324	122,072
1998	3.5	4,955,018	50.00	46.71	0.9342	1.0000	4,628,863	99,094
1997	4.5	3,793,210	50.01	45.78	0.9154	1.0000	3,472,377	75,846
1996	5.5	4,083,725	49.98	44.86	0.8974	1.0000	3,664,900	81,704
1995	6.5	3,410,349	50.01	43.93	0.8785	1.0000	2,995,827	68,189
1994	7.5	3,227,765	50.03	43.02	0.8599	1.0000	2,775,504	64,519
1993	8.5	1,623,283	49.89	42.11	0.8440	1.0000	1,370,113	32,539
1992	9.5	973,515	50.05	41.20	0.8232	1.0000	801,355	19,450
1991	10.5	(23,444)	49.50	40.30	0.8141	1.0000	(19,086)	(474)
1990	11.5	1,198,215	50.09	39.41	0.7867	1.0000	942,635	23,921
1989	12.5	843,235	50.12	38.52	0.7685	1.0000	648,062	16,825
1988	13.5	728,417	50.14	37.64	0.7506	1.0000	546,773	14,528
1987	14.5	614,660	50.16	36.76	0.7328	1.0000	450,433	12,253
1986	15.5	522,390	50.15	35.89	0.7157	1.0000	373,866	10,416
1985	16.5	406,944	50.23	35.03	0.6974	1.0000	283,798	8,101
1984	17.5	396,579	50.28	34.18	0.6798	1.0000	269,596	7,888
1983	18.5	231,381	50.31	33.33	0.6625	1.0000	153,279	4,599
1982	19.5	287,371	50.36	32.49	0.6452	1.0000	185,416	5,706
1981	20.5	434,828	50.40	31.66	0.6282	1.0000	273,154	8,627
1980	21.5	240,970	50.43	30.84	0.6115	1.0000	147,356	4,778
1979	22.5	262,412	50.52	30.03	0.5943	1.0000	155,949	5,194
1978	23.5	202,057	50.61	29.22	0.5773	1.0000	116,652	3,992
1977	24.5	15,297	50.45	28.42	0.5634	1.0000	8,618	303
1976	25.5	32,733	50.75	27.63	0.5445	1.0000	17,824	645
1975	26.5	142,712	50.83	26.86	0.5284	1.0000	75,403	2,808
1974	27.5	207,637	50.91	26.09	0.5124	1.0000	106,392	4,078
1973	28.5	154,987	51.05	25.33	0.4961	1.0000	76,894	3,036
1972	29.5	154,008	51.14	24.58	0.4806	1.0000	74,013	3,011
1971	30.5	125,621	51.25	23.84	0.4651	1.0000	58,428	2,451
1970	31.5	79,402	51.40	23.11	0.4496	1.0000	35,698	1,545
1969	32.5	61,328	51.41	22.39	0.4356	1.0000	26,712	1,193
1968	33.5	65,079	51.66	21.68	0.4198	1.0000	27,319	1,260
1967	34.5	53,815	51.65	20.99	0.4063	1.0000	21,866	1,042
1966	35.5	49,071	51.84	20.30	0.3916	1.0000	19,218	947
1965	36.5	50,207	52.02	19.63	0.3773	1.0000	18,945	965

NORTHERN ARIZONA GAS DIVISION
Distribution Plant
Account: 380.00 Services

Dispersion: 50 - R2.5
Procedure: Vintage Group

Generation Arrangement

	December 31, 2001				Net			
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1964	37.5	40,755	51.94	18.97	0.3653	1.0000	14,886	785
1963	38.5	38,102	51.97	18.32	0.3526	1.0000	13,434	733
1962	39.5	23,896	51.45	17.69	0.3438	1.0000	8,216	464
1961	40.5	26,820	48.46	17.07	0.3522	1.0000	9,446	553
1960	41.5	30,931	53.27	16.46	0.3091	1.0000	9,559	581
1959	42.5	25,245	52.18	15.87	0.3042	1.0000	7,678	484
1958	43.5	28,663	53.24	15.29	0.2873	1.0000	8,234	538
1957	44.5	31,900	54.04	14.73	0.2727	1.0000	8,698	590
1956	45.5	29,807	54.28	14.19	0.2615	1.0000	7,793	549
1955	46.5	27,084	53.00	13.66	0.2578	1.0000	6,982	511
1954	47.5	26,818	54.67	13.15	0.2406	1.0000	6,452	491
1953	48.5	40,085	54.62	12.66	0.2317	1.0000	9,289	734
1952	49.5	128,379	54.63	12.18	0.2230	1.0000	28,629	2,350
1951	50.5	120,249	54.58	11.72	0.2148	1.0000	25,827	2,203
Total	6.6	$47,317,504	50.10	44.07	0.8797	1.0000	$41,624,389	$944,417

NORTHERN ARIZONA GAS DIVISION
Distribution Plant
Account: 380.00 Services

Age Distribution

Vintage	Age as of 12/31/2001	Derived Additions	1951 Opening Balance	Experience to 12/31/2001 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2001	0.5	8,476,447		8,476,447	1.0000	0.5000
2000	1.5	2,531,433		2,513,493	0.9929	1.4965
1999	2.5	6,104,258		6,104,053	1.0000	2.5000
1998	3.5	4,995,019		4,955,018	0.9920	3.4960
1997	4.5	3,796,288		3,793,210	0.9992	4.4992
1996	5.5	4,189,315		4,083,725	0.9748	5.4625
1995	6.5	3,448,273		3,410,349	0.9890	6.4859
1994	7.5	3,275,402		3,227,765	0.9855	7.4902
1993	8.5	1,894,101		1,623,283	0.8570	8.3377
1992	9.5	996,428		973,515	0.9770	9.4885
1991	10.5	728,323		(23,444)	-0.0322	9.9235
1990	11.5	1,219,707		1,198,215	0.9824	11.4912
1989	12.5	848,855		843,235	0.9934	12.4967
1988	13.5	738,083		728,417	0.9869	13.4932
1987	14.5	618,981		614,660	0.9930	14.4898
1986	15.5	532,108		522,390	0.9817	15.4460
1985	16.5	407,178		406,944	0.9994	16.4915
1984	17.5	399,650		396,579	0.9923	17.4961
1983	18.5	232,628		231,381	0.9946	18.4920
1982	19.5	288,273		287,371	0.9969	19.4883
1981	20.5	437,561		434,828	0.9938	20.4782
1980	21.5	242,945		240,970	0.9919	21.4505
1979	22.5	263,326		262,412	0.9965	22.4790
1978	23.5	202,333		202,057	0.9986	23.4993
1977	24.5	15,461		15,297	0.9894	24.2613
1976	25.5	33,142		32,733	0.9877	25.4815
1975	26.5	144,062		142,712	0.9906	26.4710
1974	27.5	208,727		207,637	0.9948	27.4562
1973	28.5	155,284		154,987	0.9981	28.4895
1972	29.5	154,358		154,008	0.9977	29.4683
1971	30.5	126,293		125,621	0.9947	30.4559
1970	31.5	79,471		79,402	0.9991	31.4711
1969	32.5	63,080		61,328	0.9722	32.3352
1968	33.5	65,549		65,079	0.9928	33.4282
1967	34.5	54,805		53,815	0.9819	34.2610
1966	35.5	50,404		49,071	0.9736	35.2711
1965	36.5	50,957		50,207	0.9853	36.2616
1964	37.5	43,042		40,755	0.9469	36.9707

NORTHERN ARIZONA GAS DIVISION
Distribution Plant
Account: 380.00 Services

Age Distribution

Vintage	Age as of 12/31/2001	Derived Additions	1951 Opening Balance	Experience to 12/31/2001 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1963	38.5	39,779		38,102	0.9578	37.7856
1962	39.5	28,006		23,896	0.8532	38.0280
1961	40.5	34,912		26,820	0.7682	35.7975
1960	41.5	31,251		30,931	0.9898	41.3326
1959	42.5	31,665		25,245	0.7973	40.9630
1958	43.5	29,643		28,663	0.9669	42.7194
1957	44.5	32,240		31,900	0.9895	44.1957
1956	45.5	30,230		29,807	0.9860	45.0908
1955	46.5	30,302		27,084	0.8938	44.4512
1954	47.5	27,977		26,818	0.9586	46.7350
1953	48.5	42,444		40,085	0.9444	47.2815
1952	49.5	155,070		128,379	0.8279	47.8543
1951	50.5	133,797		120,249	0.8987	48.3523
1950	51.5		290		0.0001	50.0001
Total		$48,758,866	$290	$47,317,504	0.9704	

NORTHERN ARIZONA GAS DIVISION
Distribution Plant
Account: 380.00 Services

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1951		134,088			134,088
1952	134,088	155,070			289,158
1953	289,158	42,443			331,601
1954	331,601	27,976			359,577
1955	359,577	30,303			389,880
1956	389,880	30,230	23		420,087
1957	420,087	32,239			452,326
1958	452,326	29,643			481,969
1959	481,969	31,665			513,634
1960	513,634	31,251			544,885
1961	544,885	34,912			579,797
1962	579,797	28,006	442		607,361
1963	607,361	39,780	1,334		645,807
1964	645,807	43,041	1,289		687,559
1965	687,559	50,957	596		737,920
1966	737,920	50,404	391		787,933
1967	787,933	54,805	3,092		839,646
1968	839,646	65,549	3,633		901,562
1969	901,562	63,080	756		963,886
1970	963,886	79,560	898		1,042,548
1971	1,042,548	126,293	646		1,168,195
1972	1,168,195	154,358	899		1,321,654
1973	1,321,654	155,285			1,476,939
1974	1,476,939	208,727	663		1,685,003
1975	1,685,003	143,538	3,351		1,825,190
1976	1,825,190	33,142			1,858,332
1977	1,858,332	15,461			1,873,793
1978	1,873,793	202,334	269		2,075,858
1979	2,075,858	263,328	4,007		2,335,179
1980	2,335,179	242,946	2,035		2,576,090
1981	2,576,090	437,561	449		3,013,202
1982	3,013,202	288,273	780		3,300,695
1983	3,300,695	232,628	414		3,532,909
1984	3,532,909	399,650	3,916		3,928,643
1985	3,928,643	407,178	1,105		4,334,716
1986	4,334,716	525,215	1,203		4,858,728
1987	4,858,728	618,982	3,606		5,474,104
1988	5,474,104	738,084	2,025		6,210,163
1989	6,210,163	848,855	2,306		7,056,712
1990	7,056,712	1,219,707	1,482		8,274,937

NORTHERN ARIZONA GAS DIVISION

Distribution Plant

Account: 380.00 Services

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1991	8,274,937	728,323	4,285	(1,562,175)	7,436,800
1992	7,436,800	996,428			8,433,228
1993	8,433,228	1,894,101	2,129	(89)	10,325,111
1994	10,325,111	3,275,402	3,736	1,562,175	15,158,952
1995	15,158,952	3,448,273	7		18,607,218
1996	18,607,218	4,189,315	8,683		22,787,850
1997	22,787,850	3,796,288	4,731		26,579,407
1998	26,579,407	4,978,361	14,617		31,543,151
1999	31,543,151	6,026,657		7,412	37,577,220
2000	37,577,220	2,523,573	333,677	198,897	39,966,013
2001	39,966,013	8,333,090	1,028,177	46,578	47,317,504

NORTHERN ARIZONA GAS DIVISION

Distribution Plant

Account: 380.00 Services

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1951		134,088			134,088
1952	134,088	155,070			289,158
1953	289,158	42,443			331,601
1954	331,601	27,976			359,577
1955	359,577	30,303			389,880
1956	389,880	30,230	23		420,087
1957	420,087	32,239			452,326
1958	452,326	29,643			481,969
1959	481,969	31,665			513,634
1960	513,634	31,251			544,885
1961	544,885	34,912			579,797
1962	579,797	28,006	442		607,361
1963	607,361	39,780	1,334		645,807
1964	645,807	43,041	1,289		687,559
1965	687,559	50,957	596		737,920
1966	737,920	50,404	391		787,933
1967	787,933	54,805	3,092		839,646
1968	839,646	65,549	3,633		901,562
1969	901,562	63,080	756		963,886
1970	963,886	79,471	898		1,042,459
1971	1,042,459	126,293	646		1,168,106
1972	1,168,106	154,358	899		1,321,565
1973	1,321,565	155,285			1,476,850
1974	1,476,850	208,727	663		1,684,914
1975	1,684,914	143,538	3,351		1,825,101
1976	1,825,101	33,142			1,858,243
1977	1,858,243	15,461			1,873,704
1978	1,873,704	202,334	269		2,075,769
1979	2,075,769	263,327	4,007		2,335,089
1980	2,335,089	242,946	2,035		2,576,000
1981	2,576,000	437,561	449		3,013,112
1982	3,013,112	288,273	780		3,300,605
1983	3,300,605	232,628	414		3,532,819
1984	3,532,819	399,650	3,916		3,928,553
1985	3,928,553	407,178	1,105		4,334,626
1986	4,334,626	525,215	1,203		4,858,638
1987	4,858,638	618,982	3,606		5,474,014
1988	5,474,014	738,084	2,025		6,210,073
1989	6,210,073	848,855	2,306		7,056,622
1990	7,056,622	1,219,707	1,482		8,274,847

NORTHERN ARIZONA GAS DIVISION

Distribution Plant

Account: 380.00 Services

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1991	8,274,847	728,323	4,285	(1,562,175)	7,436,710
1992	7,436,710	996,428			8,433,138
1993	8,433,138	1,894,101	2,129		10,325,110
1994	10,325,110	3,275,402	3,736	1,562,175	15,158,951
1995	15,158,951	3,448,273	7		18,607,217
1996	18,607,217	4,189,315	8,683		22,787,849
1997	22,787,849	3,796,288	4,731		26,579,406
1998	26,579,406	4,995,018	14,617		31,559,807
1999	31,559,807	6,104,259		7,412	37,671,478
2000	37,671,478	2,531,433	333,677		39,869,234
2001	39,869,234	8,476,447	1,028,177		47,317,504

NORTHERN ARIZONA GAS DIVISION

Distribution Plant

Account: 380.00 Services

T-Cut: None

Placement Band: 1950-2001

Hazard Function: Proportion Retired

Weighting: Exposures

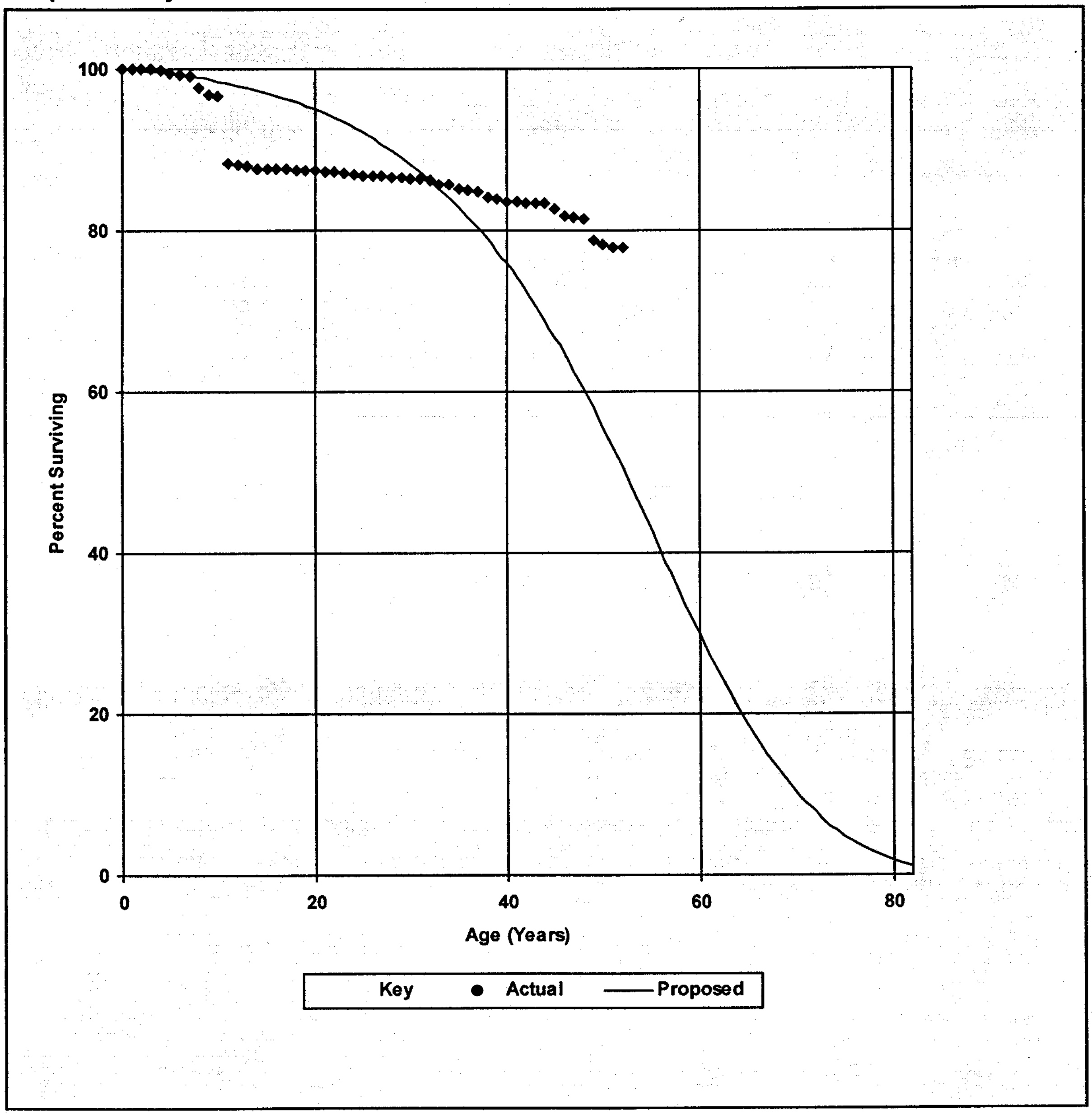
Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1951-1990	94.4	134.3	S0*	2.61	99.1	S1.5	1.10	80.5	S2	1.53
1952-1991	95.2	139.3	R1*	3.16	109.7	S1	0.79	153.9	R0.5 *	11.69
1953-1992	95.5	143.2	R1*	3.69	119.8	S1	0.67	186.4	R4 *	15.25
1954-1993	95.4	143.6	R1*	3.74	123.1	S1 *	0.94	189.7	R5 *	14.41
1955-1994	95.1	141.6	R1*	3.44	118.8	S1 *	0.67	189.7	R5 *	14.42
1956-1995	95.5	146.3	R1*	4.23	130.9	S0.5 *	1.67	190.9	R5 *	13.96
1957-1996	93.6	137.8	R1*	3.01	97.5	S1.5	0.50	128.7	S-.5 *	7.07
1958-1997	92.6	135.8	S0*	2.83	91.5	S1.5	0.75	79.6	R3	1.44
1959-1998	91.7	133.1	S0*	2.40	92.5	S1.5	0.52	81.3	S2 *	1.50
1960-1999	92.4	137.8	R1*	3.01	98.2	S1.5	0.50	95.0	S1.5	0.79
1961-2000	0.0	136.8	R0.5	3.98	97.9	S1	0.98	62.1	R4 *	1.71
1962-2001	77.9	92.2	L0	1.26	159.7	R1 *	18.58	51.8	R2.5 *	7.77

NORTHERN ARIZONA GAS DIVISION
Distribution Plant
Account: 380.00 Services

T-Cut: None
Placement Band: 1950-2001
Observation Band: 1962-2001
50.0-R2.5

Proposed Projection Life Curve



NORTHERN ARIZONA GAS DIVISION

Distribution Plant

Account: 380.00 Services

Balances Analysis

Rank by Index of Variation				Rank by Combined Index				
Life/ Curve	SSQ	IOV	REI	Life/ Curve	SSQ	IOV	REI	CI
A	B	C	D	E	F	G	H	I
		Band: 1962-2001		**Points: 40**	**Interval: 0**			
250.0 - R0.5	1.196E+12	20	8.2	46.7 - SQ	1.243E+12	21	100.0	21
126.1 - R1.5	1.208E+12	20	10.5	44.6 - S6	1.227E+12	21	97.9	21
44.6 - S6	1.227E+12	21	97.9	44.3 - S5	1.265E+12	21	91.2	23
86.7 - R2	1.233E+12	21	15.0	44.2 - R5	1.253E+12	21	90.4	23
46.7 - SQ	1.243E+12	21	100.0	45.1 - L5	1.289E+12	21	82.8	25
44.2 - R5	1.253E+12	21	90.4	44.9 - S4	1.309E+12	21	79.4	27
		Band: 1972-2001		**Points: 30**	**Interval: 0**			
250.0 - R0.5	1.196E+12	18	8.2	46.7 - SQ	1.243E+12	18	100.0	18
126.1 - R1.5	1.208E+12	18	10.5	44.6 - S6	1.226E+12	18	97.9	19
44.6 - S6	1.226E+12	18	97.9	44.3 - S5	1.265E+12	19	91.2	20
86.7 - R2	1.233E+12	18	15.1	44.2 - R5	1.252E+12	18	90.4	20
46.7 - SQ	1.243E+12	18	100.0	45.1 - L5	1.289E+12	19	82.8	23
44.2 - R5	1.252E+12	18	90.4	44.9 - S4	1.308E+12	19	79.4	24
		Band: 1982-2001		**Points: 20**	**Interval: 0**			
250.0 - R0.5	1.193E+12	16	8.2	46.7 - SQ	1.239E+12	16	100.0	16
125.5 - R1.5	1.205E+12	16	10.6	44.6 - S6	1.222E+12	16	97.9	16
44.6 - S6	1.222E+12	16	97.9	44.3 - S5	1.261E+12	16	91.2	18
86.4 - R2	1.231E+12	16	15.2	44.2 - R5	1.249E+12	16	90.4	18
46.7 - SQ	1.239E+12	16	100.0	45.1 - L5	1.286E+12	16	82.8	20
44.2 - R5	1.249E+12	16	90.4	44.9 - S4	1.306E+12	16	79.4	21
		Band: 1992-2001		**Points: 10**	**Interval: 0**			
250.0 - R0.5	1.163E+12	13	8.2	46.7 - SQ	1.227E+12	14	100.0	14
119.3 - R1.5	1.166E+12	13	11.4	44.7 - S6	1.214E+12	13	97.8	14
250.0 - SC	1.184E+12	13	10.3	44.3 - S5	1.257E+12	14	91.4	15
82.8 - R2	1.190E+12	13	16.5	44.1 - R5	1.245E+12	14	90.7	15
125.7 - L0.5	1.205E+12	13	16.0	45.1 - L5	1.282E+12	14	83.0	17
44.7 - S6	1.214E+12	13	97.8	44.7 - S4	1.296E+12	14	80.6	17

SSQ: Sum of Squared Differences *IOV: Index of Variation* *REI:Retirement Experience Index* *CI:Combined Inde*

NORTHERN ARIZONA GAS DIVISION
Distribution Plant
Account: 380.00 Services

Annual Retirements Analysis

Rank by Index of Variation				Rank by Combined Index				
Life/ Curve	SSQ	IOV	REI	Life/ Curve	SSQ	IOV	REI	CI
A	B	C	D	E	F	G	H	I
Band: 1962-2001				**Points: 40**	**Interval: 0**			
47.4 - L0	6.847E+11	3630	59.8	25.2 - S1	7.358E+11	3763	100.0	3763
33.5 - S0	6.947E+11	3657	84.5	29.1 - R2	7.395E+11	3773	99.8	3779
140.2 - O4	6.953E+11	3658	37.3	25.6 - R2.5	7.517E+11	3804	100.0	3804
101.8 - O3	6.957E+11	3659	38.4	23.7 - S1.5	7.562E+11	3815	100.0	3815
39.3 - L0.5	6.963E+11	3661	71.8	20.4 - S6	7.654E+11	3838	100.0	3838
70.8 - O2	6.964E+11	3661	40.7	23.3 - R3	7.735E+11	3858	100.0	3858
Band: 1972-2001				**Points: 30**	**Interval: 0**			
47.4 - L0	6.842E+11	3171	59.9	25.1 - S1	7.344E+11	3286	100.0	3286
33.5 - S0	6.940E+11	3194	84.5	29.0 - R2	7.390E+11	3296	99.9	3301
140.1 - O4	6.950E+11	3196	37.3	25.5 - R2.5	7.509E+11	3322	100.0	3322
101.7 - O3	6.954E+11	3197	38.4	23.5 - S1.5	7.546E+11	3331	100.0	3331
39.3 - L0.5	6.957E+11	3198	71.8	20.3 - S6	7.599E+11	3342	100.0	3342
70.7 - O2	6.961E+11	3199	40.8	23.2 - R3	7.724E+11	3370	100.0	3370
Band: 1982-2001				**Points: 20**	**Interval: 0**			
47.0 - L0	6.809E+11	2605	60.3	24.8 - S1	7.253E+11	2688	100.0	2688
33.3 - S0	6.896E+11	2621	85.1	28.4 - R2	7.334E+11	2703	100.0	2704
39.0 - L0.5	6.916E+11	2625	72.2	20.4 - S6	7.377E+11	2711	100.0	2711
139.4 - O4	6.929E+11	2627	37.5	25.1 - R2.5	7.416E+11	2718	100.0	2718
101.2 - O3	6.933E+11	2628	38.6	23.3 - S1.5	7.435E+11	2722	100.0	2722
45.5 - S-.5	6.934E+11	2628	57.8	29.2 - S0.5	7.076E+11	2655	96.6	2747
Band: 1992-2001				**Points: 10**	**Interval: 0**			
45.4 - L0	6.558E+11	1835	62.3	23.8 - S1	6.745E+11	1861	100.0	1861
31.9 - S0	6.575E+11	1837	88.3	27.7 - S0.5	6.690E+11	1853	98.8	1876
37.6 - L0.5	6.628E+11	1845	74.7	22.4 - S1.5	6.921E+11	1885	100.0	1885
27.7 - S0.5	6.690E+11	1853	98.8	26.5 - R2	6.932E+11	1886	100.0	1886
30.7 - L1	6.694E+11	1854	88.2	20.3 - S6	6.986E+11	1894	100.0	1894
43.6 - S-.5	6.712E+11	1856	60.7	24.4 - R2.5	6.989E+11	1894	100.0	1894

SSQ: Sum of Squared Differences *IOV: Index of Variation* *REI:Retirement Experience Index* *CI:Combined Inde*

NORTHERN ARIZONA GAS DIVISION

Distribution Plant

Account: 380.00 Services

Computed Mortality **Projection Curve: R2.5**

Year	Additions	Plant Balance Adjusted	Plant Balance Computed	Plant Balance Difference	Average Service Life
A	B	C	D	E=C-D	F
1951	133,951	133,951	133,951		No Rets.
1952	154,713	288,664	288,664		No Rets.
1953	42,330	330,993	330,993		No Rets.
1954	27,894	358,888	358,888		No Rets.
1955	30,208	389,095	389,095		No Rets.
1956	30,126	419,199	419,199		969.97
1957	32,119	451,318	451,318		No Rets.
1958	29,524	480,842	480,842		No Rets.
1959	31,529	512,371	512,371		No Rets.
1960	31,107	543,478	543,478		No Rets.
1961	34,742	578,220	578,220		No Rets.
1962	27,862	605,642	605,642		100.48
1963	39,560	643,875	643,875		51.03
1964	42,786	685,380	685,380		55.39
1965	50,633	735,421	735,421		97.03
1966	50,061	785,093	785,093		140.76
1967	54,405	836,429	836,429		41.54
1968	65,031	897,856	897,856		40.61
1969	62,545	959,652	959,652		103.83
1970	78,738	1,037,500	1,037,500		98.04
1971	124,985	1,161,845	1,161,845		132.35
1972	152,549	1,313,505	1,313,505		113.45
1973	153,245	1,466,751	1,466,751		No Rets.
1974	205,561	1,671,659	1,671,659		168.97
1975	141,156	1,809,519	1,809,519		62.54
1976	32,581	1,842,100	1,842,100		No Rets.
1977	15,197	1,857,297	1,857,297		No Rets.
1978	198,449	2,055,483	2,055,483		448.19
1979	257,426	2,308,992	2,308,992		68.14
1980	236,794	2,543,803	2,543,803		107.64
1981	423,965	2,967,333	2,967,333		385.95
1982	277,978	3,244,559	3,244,559		266.12
1983	223,127	3,467,289	3,467,289		500.93
1984	379,653	3,843,222	3,843,222		93.44
1985	382,474	4,224,658	4,224,658		253.83
1986	485,903	4,709,449	4,709,449		260.42
1987	560,482	5,266,666	5,266,666		123.78
1988	650,996	5,915,876	5,915,876		210.99
1989	713,635	6,627,573	6,627,573		216.19
1990	889,959	7,516,450	7,516,450		394.82

NORTHERN ARIZONA GAS DIVISION
Distribution Plant
Account: 380.00 Services

Computed Mortality **Projection Curve: R2.5**

Year	Additions	Plant Balance Adjusted	Plant Balance Computed	Difference	Average Service Life
A	B	C	D	E=C-D	F
1991	439,931	7,953,792	7,953,792		202.63
1992	1,165,874	9,119,666	9,119,666		No Rets.
1993	2,216,200	11,333,375	11,333,375		261.09
1994	3,832,396	15,161,399	15,161,399		198.13
1995	3,449,034	18,610,426	18,610,426		No Rets.
1996	4,190,239	22,791,980	22,791,980		158.65
1997	3,797,125	26,584,373	26,584,373		310.73
1998	4,996,120	31,565,873	31,565,873		136.02
1999	6,105,605	37,671,478	37,671,478		No Rets.
2000	2,531,433	39,869,234	39,869,234		32.01
2001	8,476,447	47,317,504	47,317,504		23.48

NORTHERN ARIZONA GAS DIVISION

Distribution Plant

Account: 38000 Services

Unadjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1978	269		0.0		1,752	651.3		(1,752)	-651.3	
1979	4,007		0.0		982	24.5		(982)	-24.5	
1980	2,035		0.0		4,343	213.4		(4,343)	-213.4	
1981	449		0.0		2,506	558.1		(2,506)	-558.1	
1982	780		0.0	0.0	3,047	390.6	167.5	(3,047)	-390.6	-167.5
1983	414		0.0	0.0	2,982	720.3	180.4	(2,982)	-720.3	-180.4
1984	3,916		0.0	0.0	2,248	57.4	199.2	(2,248)	-57.4	-199.2
1985	1,105		0.0	0.0	1,332	120.5	181.8	(1,332)	-120.5	-181.8
1986	1,203		0.0	0.0	4,735	393.6	193.4	(4,735)	-393.6	-193.4
1987	3,606		0.0	0.0	2,627	72.9	135.9	(2,627)	-72.9	-135.9
1988	2,025		0.0	0.0	1,065	52.6	101.3	(1,065)	-52.6	-101.3
1989	2,306		0.0	0.0	6,053	262.5	154.3	(6,053)	-262.5	-154.3
1990	1,482		0.0	0.0	13,898	937.8	267.2	(13,898)	-937.8	-267.2
1991	4,285		0.0	0.0	17,608	410.9	301.0	(17,608)	-410.9	-301.0
1992			0.0	0.0		0.0	382.5		0.0	-382.5
1993	2,129		0.0	0.0		0.0	368.2		0.0	-368.2
1994	3,736		0.0	0.0		0.0	270.9		0.0	-270.9
1995	7		0.0	0.0		0.0	173.4		0.0	-173.4
1996	8,683		0.0	0.0		0.0	0.0		0.0	0.0
1997	4,731		0.0	0.0	132	2.8	0.7	(132)	-2.8	-0.7
1998	14,617		0.0	0.0		0.0	0.4		0.0	-0.4
1999			0.0	0.0		0.0	0.5		0.0	-0.5
2000	333,677		0.0	0.0	7,295	2.2	2.1	(7,295)	-2.2	-2.1
2001	1,028,177		0.0	0.0	25,058	2.4	2.4	(25,058)	-2.4	-2.4
Total	1,423,638		0.0		97,664	6.9		(97,664)	-6.9	